

Virginia City Hybrid Energy Center
Response to Data Request
Bruce Buckheit, Member, Virginia Air Pollution Control Board

Question (Page No. 3-5):

This question has seven parts and they are restated throughout the response in bold text.

Response:

#1 – “Overall Goal is to produce a spreadsheet that will enable a determination of the most effective control technology for the Top Down BACT process as well as to evaluate the technology selected.”

Dominion conducted a top down BACT analysis in accordance with EPA’s 1990 New Source Review Workshop Manual and submitted it in the June 2006 and August 2007 air permit applications (Attachment 1). This response supplements that submittal with additional information.

Based on the top down BACT analysis, Dominion has committed to install the best, technically feasible control device for each of the criteria pollutants (SNCR for NO_x, limestone injection and FGD for SO₂, fabric filters for PM and good combustion practices for CO and VOC) for the design fuels and combustion technology (CFB). Dominion has included an extensive list of the most recently permitted CFB facilities (Attachment 2) that was included in the March 6, 2008 submittal to DEQ.

SO₂ is the only criteria pollutant that has the potential to experience a reduction in emissions due to coal washing. NO_x and particularly thermal NO_x may be adversely affected by going to a higher quality coal.

SO₂ emissions from any given coal-fired boiler are affected by the APC system and are related to the range of sulfur found in the coal, as illustrated in the bar chart prepared by Mr. Buckheit on page 3 of the information request.

Virginia coal is “washed” (pre-cleaned) every day in order to be suitable for consumption in a pulverized coal facility. This washing process produces in some cases marginally higher sulfur content coal on a percent by weight basis. Further information on the technical feasibility, economic and environmental impacts of using lower sulfur fuels for the proposed VCHEC are addressed in following responses.

#2 – “Assumptions about control device efficiencies may alter ranking of control device strategies and so should be explored and presented as the technical review progresses.”

Assumptions about control device efficiencies are based on data available to Dominion. The proposed SO₂ emission limit is based on the maximum control efficiency appropriate for this project. For the other pollutants, it is more appropriate to analyze the proposed emission rate and the factors that affect that pollutant. Control efficiencies are not appropriate for CO or VOC because there is no control device feasible to control these pollutants from a CFB boiler. Control efficiency for PM emissions is also not appropriate because in general, a fabric filter is going to have constant PM emissions and the control efficiency will vary as the ash loading to the filters varies, i.e. more ash to the filters given a constant emission rate yields a higher efficiency. As a result, SO₂ is the only criteria pollutant for which reviewing control efficiencies can have a meaningful impact on determining the appropriate stack emissions.

The control efficiency of a pollution control device is more relevant to the addition of end of pipe controls to an existing unit than to the design of a new unit. In the latter case, the design focuses on the ultimate emissions from the boiler/control equipment system as a whole. In particular, efforts are made to prevent the formation of pollutants in the boiler as well as control of those emissions in the pollution control devices. In this way, the burden of overall emission reduction is divided among the system components. This is particularly true, for example, in the case of NO_x emissions. New boiler and burner design greatly reduce NO_x formation as compared to previous designs imposing less uncontrolled emissions to the SNCR.

With regard to SO₂ emissions, the best control technology is limestone injection and flue gas desulfurization. This combination is regarded as the best available control technology for CFB boilers. The best combinations of SO₂ boiler and APC technology achieve about 98% reduction of SO₂ formed as a result of the oxidation of fuel sulfur. The combination of control technologies that has been used to achieve the maximum level of SO₂ control includes sorbent injection followed by a polishing scrubber or wet flue gas desulfurization (such as for a PC unit) with or without polishing wet ESP.

The design of the SO₂ control system reflects the maximum design coal sulfur content capability of that system and coal purchase specifications are established on the basis of not greater than that maximum design coal sulfur content. In daily practice, therefore, the actual sulfur content of the coal being supplied will typically be less than the maximum

design basis and actual stack emissions will be less than allowed. Finally, maximum annual SO₂ emissions are permitted based on a potential capacity factor of 100%, whereas actual annual SO₂ emissions as reported to EPA's Clean Air Markets web site reflect historical capacity factor, indicating that all facilities emit less SO₂ than actually allowed by permit. Stack test data from Dominion's own facilities reflect these statistical variabilities, meaning that all compliant stack test data document SO₂ emission levels at or below permit limits, and based on specific conditions at any given time may be significantly lower.

This disparity exists at every coal unit and will also be experienced at the proposed VCHEC. Importantly, SO₂ emission control levels must be established as enforceable limits that can be achieved continuously for year after year of operation. Simply because a given unit recorded a low emission rate at some point in its operation that does not mean it could continue to operate at a lower enforceable permit limit all of the time. For these reasons, we believe that actual stack emission data will always reflect lower SO₂ mass emissions than allowed via permitted limits, and that this margin will exist equally for all top level of control equipped facilities (including the proposed VCHEC). Thus, we believe the best practical measure of SO₂ reduction demonstrated continuously in practice is continuous compliance with an enforceable emission limitation. Consideration of actual stack emission data is useful only to the extent that it demonstrates how much lower actual emissions of SO₂ may be compared with permitted not-to-exceed limits.

In theory, multiple SO₂ devices of similar or varying descriptions can be strung together to achieve incrementally greater removal. The ability of any scrubber to capture a given % of SO₂ declines rapidly with declining inlet concentration. Thus, if a third scrubber were to be installed after two installed in series (limestone injection, FGD) that collectively achieve 98% reduction, the inlet SO₂ concentration would be so low that within the fixed geometry and residence time of that third scrubber its ability to capture additional SO₂ would be minimal compared with that of the first. In the extreme, as the SO₂ concentration approaches zero, collection efficiency also approaches zero. Thus, there is a rapidly diminishing return (in terms of incremental SO₂ capture) accompanied by a similarly rapidly decreasing incremental cost effectiveness for employing additional stages of control.

The capabilities of never before applied combinations or additional stages of control technology are highly speculative and not demonstrated or achieved in practice. As indicated in other submittals the BACT process looks at technologies and emission limits that have been demonstrated in practice.

We conclude that there are multiple combinations of coal-fired generation and SO₂ control technology that are capable of best level (98%) reduction of SO₂ generated due to the oxidation of sulfur in coal. Any of these demonstrated control alternatives, including the CFB limestone injection followed by a polishing spray dryer and fabric filter proposed for the VCHEC, reflect the best level of SO₂ reduction that has been achieved in practice, and therefore the top level of control for SO₂ BACT.

#3 – “Results should be presented on an input basis and on an output basis.”

Discussion in #8 and the attachments show potential emissions on an input (lbs/mmBtu) and output (lbs/MWhr) basis.

#4 – “Costs should be presented on the basis of competing assumptions, but based on sound science – thus, when comparing control costs/ton the results should be normalized to account for the fact that existing units incur a cost for purchasing cleaned coal that is not reflected in the classic BACT figures employed by agencies. Indeed coal washing has been thoroughly studied and commonly understood as the most cost effective strategy for reducing SO₂ emissions. Since the adoption of the Acid Rain program in 1990 it has been the most commonly employed SO₂ control strategy.”

Page B-3 of the 1990 New Source Review Workshop Manual states, *“The PSD applicant first examines the most stringent--or “top”--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case.”* Review of costs for control equipment was not required for the VCHEC project because the top, technically feasible control technology is proposed for each criteria pollutant.

With regard to coal washing, see response to comment number 1.

#5 – “Any “worst case” estimates should be accompanied by the most accurate estimate.”

Worst case emission estimates are presented based on maximum allowable SO₂ emission limits and 100% capacity factor based on all fuel having the maximum design sulfur

content (the annual potential to emit, pte). The values in the VCHEC application are similarly worst case (based on pte), and therefore allow for direct comparison.

It is difficult to project how much lower the actual emissions from VCHEC will be over the life of the facility, as this will depend on a combination of its annual capacity factor, actual fuel mix, % of fossil fuel that can be offset with biomass (which emits zero SO₂), and system performance based on manufacturers guarantee margin and permit margin.

#6 – “The analysis should include each of the major options suggested by commenters.”

The public comments on the PSD permit regarding control technologies focused mainly on SCR and Wet ESP. SCR is not technically feasible on a CFB because the high ash content of the flue gas would cause rapid deterioration of the catalyst. The SCR would have to be placed on the backside of the PM control device (fabric filters). At these temperatures, the exhaust gas must be re-heated in order for the catalyst to properly operate. Dominion conducted a BACT analysis on SCR for NO_x control from the CFB boilers in this configuration. The analysis dated May 24, 2007 was submitted to DEQ and showed a \$42,000 per ton NO_x removal cost. As a result, SCR was deemed uneconomical.

Wet ESP's are specified for fine particulate control in PC units, including control of condensable sulfuric acid mist aerosols from coal-fired boilers that use SCR for NO_x control followed by wet flue gas desulfurization (FGD) systems for SO₂ control. In some cases SO₂ formed in boilers from use of higher sulfur coals has been determined to partially oxidize to SO₃ across an SCR catalyst, forming sulfuric acid that is not effectively captured in the wet scrubber, resulting in blue plume. The proposed VCHEC however offers very effective control of sulfuric acid mist by employing spray dryer / fabric filter acid gas control technology. It is unclear if significant further reductions in SO₂ would be achieved with a wet ESP downstream of the proposed VCHEC air pollution control train. However, wet ESPs are used downstream of wet scrubbers and wet scrubbers were determined to not be the best control technology for VCHEC, fabric filters were determined to be the best. Wet scrubbers present problems as they result in a wet waste and they greatly increase water consumption at the facility (several million gallons per day more). Due to water constraints in the area, a wet ESP is not technically feasible. In any event, no such system has ever been demonstrated in practice to achieve levels of SO₂ reduction greater than those already proposed for VCHEC. By identifying the best controlled facilities regardless of boiler technology or combination of pollution control systems, our analysis has already captured the range of best demonstrated combinations of SO₂ reduction technologies.

#7 – “Analysis should consider, major candidate control technologies should include”;

- **Dominion's proposal – CFB/SDA/FF**
- **Washed coal/CFB/SDA/FF**
- **IGCC**

- **SCPC**
- **SCCFB**

A study was done by CH2M HILL to compare a hypothetical Best Available Control Technology (BACT) cost-effectiveness calculation a total dollar per ton of criteria pollutants between the proposed VCHEC CFB facility, the proposed AEP Mountaineer IGCC, a hypothetical IGCC, and a supercritical PC. The study analyzes cost effectiveness of the different technologies and is included in Attachment 3.

Dominion conducted a top down BACT analysis in accordance with EPA's 1990 New Source Review Workshop Manual and submitted it in the June 2006 and August 2007 air permit applications. In the top down BACT analysis, Dominion has agreed to install the top, technically feasible control device for each of the criteria pollutants (SNCR for NO_x, limestone injection and FGD for SO₂, fabric filters for PM and good combustion practices for CO and VOC) for the design fuels and combustion technology (CFB). As such, incremental and average cost comparisons are not appropriate.

A washed coal control cost analysis has also been done and was included in the March 6, 2008 submittal to DEQ. The washed coal scenario has been updated to reflect the most recent coal costs and this analysis has been included in the response to comment number 1. The washed coal analyses are hypothetical because coal washing is not appropriate for the proposed project, as addressed in the response to comment number 1.

Coal washing removes some of the impurities from the run of mine coal, such as ash by using the specific gravity differences between the coal and the impurities being removed. In order to separate the impurities from the coal, it is first crushed followed by washing based on the specific gravity of the impurity sought to be removed. A common misunderstanding of coal washing is that it will significantly reduce the unwanted impurities, such as sulfur and metals. The amount of reduction achieved depends on the chemical nature of the impurity.

Sulfur is present in coal in two forms, elemental and pyritic. Elemental sulfur has a specific gravity similar to coal so is not readily removed by coal washing. Pyritic sulfur, however, has a higher specific gravity than coal and is easier to remove. The pyritic sulfur content of southwest Virginia coal is less than in other coal regions (e.g., Northern Appalachian and Illinois basin) so coal washing of southwest Virginia coal will result in less benefits than washing of other coals.

Because of the form of sulfur typically found in southwest Virginia coal, coal washing is not as effective at removing SO₂ as the selected CFB and dry scrubber technologies proposed for VCHEC. Coal washing would reduce SO₂ emissions only negligibly or not at all, while the CFB and dry scrubber technologies would reduce SO₂ emissions by at least 98%. In the above cost analysis, Dominion assumed the lb/mmBtu of SO₂ would be reduced from 5.86 to 1.2 by using washed CAPP coal instead of the design fuel which includes ROM coal. Even assuming that reduction was accurate, CAPP coal was still cost prohibitive and not BACT for VCHEC.

Coal washing results in additional environmental impacts as a result of the waste coal piles generated. One of the goals of VCHEC is to build a CFB which can burn waste coal or “gob”. According to the Virginia Department of Mines, Minerals and Energy; there are currently hundreds of waste coal piles in southwest Virginia. These waste coal piles pose environmental risks of water quality degradation, as well as potential fire hazards.

Run off from coal waste piles causes water pollution in the form of sedimentation of streams. The Department of Mines, Minerals and Energy (DMME) is conducting a study of the water quality impacts from these waste coal sites and it is our understanding the sediment loading from just one of these sites is contributing over 17,000 pounds per acre of sediment loading annually since the waste coal was deposited on the surface. This is just an example of one waste coal site. There have been significant comments in support of the VCHEC, because it will facilitate the use of waste coal piles in the region reducing sediment loading to streams and tributaries. See the response to Issue #7 for a further discussion from the Department of Mines Minerals and Energy of the environmental benefits of waste coal reclamation on the Clinch River. Moreover, coal processing requires water. Using ROM coal rather than processed coal is consistent with VCHEC’s commitment to minimize water consumption related to its operations (as evidenced by the use of air-cooled rather than water-cooled condensers).

In addition, these unreclaimed waste coal piles pose an air quality issue when they ignite spontaneously. If a waste coal pile catches fire, uncontrolled emissions of sulfur dioxide, particulates, nitrogen oxides and mercury would be released into the environment. Combusting the waste coal piles utilizing well-controlled, clean coal technology will reduce the potential for significant air emissions should these unreclaimed waste coal piles catch fire accidentally.

Finally, coal washing results in adverse energy impacts. Not only is substantial energy required to process the coal, about 15 to 20% of the coal mined ends up as coarse and

fine coal waste. To recover the energy in that coal waste a CFB is required. It is possible to estimate the energy in the carbon bearing materials that would be disposed of during coal processing. As an example, research conducted by Miltech Energy Services, Inc. at the Moss 3 mine waste coal piles indicate that there is about a 50% yield in converting ROM coals (~7,000 Btu/lbs) to higher grade processed coal having a heat content of approximately 12,000 Btu/lb. Coal processing refuse consists of 85% coarse coal, refuse containing about 2,000 Btu/lb and about 15% fine coal refuse containing about 4,000 Btu/lb. Therefore:

$$\text{ROM Btu/lb} = (0.50 \times 12,000 \text{ Btu/lb}) + (0.50 \times 0.85 \times 2,000 \text{ Btu/lb}) + (0.50 \times 0.15 \times 4,000 \text{ Btu/lb}) = 7,150 \text{ Btu / lb}$$

$$\text{ROM Btu Recovery \%} = (7,150 \text{ Btu/lb} - 12,000 \text{ Btu/lb} \times 0.5) / (7,150 \text{ Btu/lb}) \times 100 = 16\%$$

Based on the data from Moss 3, this example shows that about 16% of the heat content contained in the ROM coal is lost in the coal cleaning process to refuse piles. This same heat content could be recovered to produce electricity by a CFB combusting the 7,150 Btu/lb ROM coal.

Additionally, processing coal requires additional energy expenditures to operate the prep plant. Because there is insufficient water at the VCHEC site to support water cooling, much less coal processing, additional fuel would be consumed to transport the ROM from the variety of operators to a prep plant and then the processed coal to the power plant. For more information on coal washing, see response to comment number 1.

#8 – “Direct impacts (per EPA manual)”

- **control effectiveness (percent pollutant removed)**
- **expected emission rate (lb/mmbtu; lb/MwH & tpy);**
- **expected emission reduction (tons per year);**
- **direct energy impacts (BTU, kWh);**
- **direct environmental impacts (other media and the emissions of toxic and hazardous air emissions)**
- **total cost effectiveness**
- **incremental cost effectiveness**

A meaningful top-down control technologies analysis specific to the VCHEC for alternative coal combustion technologies (PC / IGCC) is not possible at this time as this type of analysis would require a completely different fuel plan. Site-specific costs for the

control technologies of other combustion technologies for VCHEC are also not possible at this time because they too would depend on the fuels. The fuels proposed to be combusted for this project are not appropriate for PC or IGCC and in order to go to PC or IGCC, a new fuel plan must be developed. The fuel plan is the basis for the proposed project and has remained unchanged. A spreadsheet (Attachment 4) was developed that lists CFB, PC and IGCC technologies along with the most common control technologies for the criteria pollutants to address the above request. Costs were estimated based on EPA's Air Pollution Control Technology Fact Sheets for those controls that are considered technically feasible. Cost analyses were not included for those controls that were not considered technologically feasible. Emissions for the PC case were estimated based on best engineering judgment while the emissions for IGCC were based on the AEP Mountaineer BACT analysis.

As discussed in previous submittals, no supercritical CFB has been proposed, designed, constructed or demonstrated in the US, and to our knowledge the very first such unit is still under construction in Lagisza, Poland. As detailed in the previous submittal, the use of supercritical CFB boilers has yet to be demonstrated in practice as a candidate BACT technology for SO₂, and is not yet a proven technology for this application. In any event, the claimed net benefit in heat rate would not be fully realized in a facility designed to use low Btu waste coals and using air cooled condensers.

Supercritical PC boilers are being widely proposed and constructed in the 600 MW + size range. The use of supercritical PC technology was considered but rejected for several reasons. A PC facility would likely be required to operate a wet scrubber system. A wet scrubber would increase water consumption by several million gallons per day. Due to water consumption concerns for the Clinch River, this is not a feasible option. In addition, the use of supercritical PC technology would mandate the exclusive use of high Btu, low ash coals and would preclude the ability to utilize SO₂ free biomass which might more than offset any SO₂ emission reduction achieved from operating at greater efficiency, as well as eliminating the objectives of utilizing local non-specification coals from small production mines as well as to help VA solve legacy environmental issues associated with waste coal piles.

The conversion to supercritical PC technology would not only fundamentally redefine the project being permitted, but would also not be cost effective for the avoidance of additional emissions of SO₂.

ATTACHMENT 1

5.0 CONTROL TECHNOLOGY EVALUATION

5.1 Technical Approach

Dominion proposes to design, construct, and operate a new power plant that will largely burn run of mine (ROM) bituminous coal supplemented by waste coal and wood waste/biomass found in the coal field region of Virginia. The Virginia legislature passed the Electric Restructuring Bill that supports the proposed facility as long as it is located in Western Virginia and burns local Virginia fuel exclusively. The plant will have an approximate net generation capacity of 530 MW. According to 9 VAC 5-80, the Project must apply Best Available Control Technology (BACT) for those pollutants that are emitted in significant quantities, that is, particulate matter (PM), particulate matter with a mean diameter of less than 10 microns (PM₁₀), particulate matter with a mean diameter of less than 2.5 microns (PM_{2.5}), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), fluorides (F), and sulfuric acid mist (H₂SO₄). The Project must also apply BACT for those pollutants that are not emitted in significant quantities in accordance with Virginia SPCB regulations under 9 VAC 5 Chapter 50. The Project will include the following stationary sources: two coal-fired CFB combustors, an auxiliary boiler, an emergency diesel generator, an emergency diesel fire pump, distillate fuel oil storage tanks, and material handling equipment. This section documents the BACT analysis for all regulated pollutants emitted from the various sources at the Project.

5.1.1 Top-Down BACT Analysis

The Virginia regulations require that applicants for a PSD pre-construction permit conduct a BACT analysis for all regulated pollutants emitted in significant quantities from major stationary sources to demonstrate compliance with the control technology requirements of the PSD regulations under 40 CFR Part 51.166, as incorporated in Article 7 of 9 VAC 5 Chapter 80. According to 40 CFR 52.21(b)(12), BACT is defined as:

“an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation under Act which could be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.”

In no event must application of BACT result in emissions of any pollutant that would exceed those allowed by any applicable requirements in the SPCB regulations under 9 VAC 5 Chapter 50, New Source Performance Standards under 40 CFR Part 60, or National Emission Standards for Hazardous Air Pollutants under 40 CFR Parts 61 and 63.

The USEPA and DEQ require a “top down” approach to the BACT analysis. The process begins with the identification of the alternative control technologies available for the source category based upon a review

of: (1) those technologies required by previous BACT determinations made by the USEPA or the various state agencies; and (2) those technologies applied in practice to the same category or a similar source category by means of technology transfer. The available control technologies are then evaluated to determine whether they are technically feasible for the given application. Those control technologies found to be technically infeasible are eliminated from further consideration, while the remaining control technologies are ranked by their performance levels, from the highest to the lowest performance level. The technically feasible control technologies are then evaluated on the basis of the associated economic, energy and environmental impacts. If an alternative technology, starting with the highest performance level, is eliminated based on any of these criteria, the control technology with the next highest performance level is evaluated until a control technology qualifies as BACT. Historically, the cost effectiveness of alternative control technologies in reducing air pollutant emissions is the principle criteria used by both the USEPA and DEQ in their determinations of BACT. All evaluated control technologies must be capable of meeting the NSPS for the pollutant in question.

According to USEPA guidance, BACT may be achieved by one or a combination of the following: (1) a change in the raw material processes; (2) a process modification; and (3) an add-on control device. A change in raw materials is typically considered for industrial processes that use chemicals, such as solvents, where substitution with a lower emitting chemical may be technically feasible. In this case, the raw material is ROM bituminous coal to be combusted for the generation of electricity. Supplemental fuels include wood and waste coal. The air contaminant emissions from the combustion of various types of coals are relatively similar for all pollutants with the exception of SO₂. The sulfur content of the coal will determine the potential SO₂ emissions from the boiler. However, the Project will utilize CFB technology with limestone injection in combination with a dry flue gas desulfurization (FGD) system to control SO₂ emissions to levels achieved by coal-fired boilers fired with lower sulfur coals. The Project is obligated to combust Virginia bituminous coal as the primary fuel to satisfy the mandates of the Electric Restructuring Bill. As Virginia Power testified to State Corporation Commission, current economics in the applicable electric wholesale market (PJM) are insufficient to justify construction of this facility as a merchant plant. Hence, Virginia Power is relying upon the cost recovery opportunities provided for by the Electric Restructuring Bill, and that Bill obligates the facility to use Virginia coal. This structure will both provide sufficient economics to make the project viable, and provide economic benefit to the Virginia coal mining industry.

Similar to changes in raw materials, process modifications are typically considered for industrial processes that use chemicals, where a change in the process methods or conditions may result in lower emissions. CFB boilers which are the essential combustion technology to achieve the project's aim of complying with the Electric Restructuring Bill and burning exclusively Virginia fuels, are recognized as an inherently low emission technology for NO_x as compared to conventional coal combustion. The CFB boiler can be considered equivalent to a conventional pulverized coal (PC) unit using low-NO_x burners (LNB) and over-fire air (OFA). The high heat transfer rates and the introduction of sub-stoichiometric primary air into the circulating bed enables the CFB to operate at lower and uniform combustion temperatures, as compared to conventional PC units. Therefore, NO_x emissions from CFB boilers are lower than those from conventional PC boilers.

Coal-fired boilers generally employ various types of add-on controls to reduce NO_x, SO₂, and PM/PM₁₀ emissions. Based on a review of recently permitted coal-fired power plants, applicable literature searches, and control device information from vendors, CFB boilers typically employ the following types of add-on control technologies:

- NO_x Control: Staged combustion and selective non-catalytic reduction (SNCR).
- SO₂ Control: Limestone injection (LI) and an SO₂ polishing control device.
- PM/PM₁₀ Control: Fabric filter (Baghouse) or electrostatic precipitator (ESP).

The Project proposes to use limestone injection and dry FGD system to control SO₂ and other acid gas emissions, staged combustion and SNCR to control emissions of NO_x, and fabric filters to control PM/PM₁₀ and trace metal emissions from the CFB boilers.

5.1.2 State Control Technology Analysis

The DEQ requires the application of best available technology to new stationary sources to be located in the Commonwealth of Virginia (9 VAC 5-50-260). The DEQ defines BACT as *“a standard of performance including a visible emission standard based on the maximum degree of emission reduction for any pollutant which could be emitted from any proposed stationary source which the board, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source through the application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant”* 9 VAC 5-50-240(C). In no event must application of BACT result in emissions of any pollutant that would exceed those allowed by any applicable standard under Article 5 (9 VAC 5 Chapter 50). Accordingly, the BACT analysis must also address those pollutants that do not exceed the significance thresholds triggering review under the PSD regulations.

5.1.3 Previous BACT Determinations

Federal and state data sources were reviewed to determine the control technologies that have been applied to coal-fired power plants around the country. The review focused on the types of air pollution control technologies used in these applications, the design and performance of each air pollution control technology, and the incentive for implementing the preferred control measures. The review considered the following databases:

- National database of recently approved PSD permits for coal-fired power plants;
- Federal and state clearinghouses for air pollution control technology determinations, and
- Air pollutant emission limits established in the various State Implementation Plans.

Each of these databases has certain limitations that hinder either identifying the control devices currently employed at the power plants or determining the performance levels actually achieved in practice by the control devices. Table 5-1 provides a summary of PSD permit limits issued for all known CFB boiler projects that were permitted since 2000 and that are still under development through June 2006. The detailed information found in the national database of recently approved PSD permits for coal-fired power

plants is provided in Appendix C. The information found in the USEPA's RACT/BACT/LAER Clearinghouse (RBLC) is also provided in Appendix C. Note that many of these plants are not yet operating; hence, the emission rates have not been demonstrated in practice, a factor which argues against their application as BACT to this facility. An additional review was conducted of applicable literature and vendor information to determine whether additional or new control devices or combinations to further inform the review of the RACT/BACT/LAER Clearinghouse (RBLC) information, and is included in the discussion of control technologies where appropriate.

Table 5-1: Summary of Recent BACT Determinations for Circulating Fluidized Bed Boilers

Project	State	Size (MW)	Fuel	Permit Status	PM imit (lb/MMBtu) ^a	SO ₂ imit (lb/MMBtu)	NO _x imit (lb/MMBtu)	CO imit (lb/MMBtu)	VOC imit (lb/MMBtu)	Control Technologies ^b
Indeck Elwood	IL	660	Bituminous Petroleum Coke	10/10/03 (Final Permit)	0.015 (Filt.PM)	0.15 (30-day)	0.10 (30-day)	0.11 (1-hour)	0.004 (3-hour)	SNCR, LI, SDA, FF GCP
Manitowoc Public Utilities	WI	64	Bituminous Petroleum Coke	12/03/03 (Final Permit)	0.030 (Filt.PM)	0.125(30-day)	0.155(30-day)	0.15 (30-day)	0.013 (3-hour)	LI, FF GCP
Cleco Rodemacher Unit 3 ^c	LA	270	Bituminous Petroleum Coke Lignite	02/23/06 (Final Permit)	0.011 (Filt.PM)	0.15 (30-day)	0.07 (12-month)	0.10 (30-day), 0.15 (30-day, part-load)	0.0047 (30-day), 0.0070 (30-day, part-load)	SNCR, LI, SDA, FF GCP
EnviroPower Benton	IL	500	Bituminous Coal	07/03/01 (Final Permit)	0.015 (Filt.PM)	0.25 (30-day)	0.125(30-day)	0.27 (30-day)	0.007 (3-hour)	SNCR, LI, FF GCP
East Kentucky Power Spurlock		540	Bituminous Coal	08/04/02 (Final Permit)	0.015 (Filt.PM)	0.20 (30-day)	0.07 (30-day)	0.15 (30-day)	0.0026(3-hour)	SNCR, LI, SDA, FF GCP
AES Puerto Rico, LP	PR	454	Bituminous Coal	10/29/01 (Final Permit)	0.015 (Filt.PM) 0.015 (Tot.PM10) ^d	0.022 (3-hour)	0.10(24-hour)	0.10 (8-hour)	0.0047 (3-hour)	SNCR, LI, CDS, ESP GCP
Montana-Dakota Utilities Westmoreland	ND	175	Lignite Coal	05/3/05 (Final Permit)	0.0130 (Filt.PM) 0.0275(Tot.PM10)	0.038 (30-day)	0.09 (30-day)	0.154(3-hour)	0.005 (3-hour)	SNCR, LI, SDA, FF GCP
Southern Montana Highwood Generating	MT	250	Sub-bituminous Coal	03/30/06 (Final Permit)	0.012 (Filt.PM) 0.026 (Tot.PM10)	0.057 (3-hour) 0.048(24-hour) 0.038(30-day)	0.10 (1-hour) 0.09(24-hour) 0.07(30-day)	0.10 (3-hour)	0.003 (3-hour)	SNCR, LI, FAR, FF GCP
NEVCO Energy Sevier Power	UT	270	Sub-bituminous Coal	10/12/04 (Final Permit)	0.0154 (Filt.PM)	0.050(24-hour) 0.022 (30-day)	0.10(24-hour)	0.115(1-hour)	0.005 (1-hour)	SNCR, LI, SDA, FF GCP
Kentucky Mountain Power Northside		500	Waste Coal	05/04/01 (Final Permit)	0.015 (Filt.PM)	0.13 (30-day)	0.07 (30-day)	0.27(24-hour)	0.0072(3-hour)	SNCR, LI, SDA, FF GCP
Robinson Power Beach Hollow	PA	270	Waste Coal	04/01/05 (Final Permit)	0.012 (Filt.PM10)	0.245 (3-hour)	0.15 (30-day)	0.15 (1-hour)	0.006 (1-hour)	SNCR, LI, SDA, FF GCP
River Hill Power	PA	270	Waste Coal	07/21/05 (Final Permit)	0.030 (Filt.PM) 0.050(CondPM10)	0.274 (3-hour) 0.200(30-day)	0.07 (30-day)	0.20 to 0.25 (1-hour)	0.0050 (1-hour)	SNCR, LI, SDA, FF GCP
Reliant Energy Seward	PA	520	Waste Coal	08/25/03 (Final Permit)	0.010 (Filt.PM10)	0.60 (3-hour)	0.15 (3-hour)	0.15 (3-hour)	0.005 (3-hour)	SNCR, LI, FAR, FF GCP
Wellington Development Greene Energy	PA	525	Waste Coal	07/05/05 (Final Permit)	0.015 (Filt.PM) 0.050 (Tot.PM10)	0.234 (3-hour) 0.156(30-day)	0.10(24-hour) 0.08 (30-day)	0.20 (1-hour)	0.005 (1-hour)	SNCR, LI, SDA, FF GCP
Western Greenbrier	WV	98	Waste Coal	04/26/06 (Final Permit)	0.015 (Filt.PM) 0.030 (Tot.PM10)	0.14 (3-hour) 0.14 (24-hour)	0.10(30-day)	0.20 (24-hour)		SNCR, LI, FDA, FF GCP
Deseret Generation Bonanza	UT	110	Waste Coal	04/14/04 (Final Permit)	0.015 (Filt.PM) 0.017 (Tot.PM10)	0.010 (30-day)	0.10 (30-day)	0.15 (3-hour)	0.000 (3-hour)	SNCR, LI, FF GCP

^a Particulate limits are specified for filterable PM (*i.e.*, Filt.PM), condensable PM₁₀ (*i.e.*, Cond.PM10) and total PM₁₀, including filterable and condensable PM₁₀ (*i.e.*, Tot.PM10).

^b SNCR refers to selective catalytic reduction; LI, limestone injection; FDA, flash dryer absorber; SDA spray dryer absorber; FF, fabric filter baghouse; CDS, circulating dry scrubber; and GCP, good combustion practices.

^c Permit includes substantially higher limits for the first 12 months of operation.

^d Permit included a provision that allows for an increase in total PM₁₀ emission limit of up to 0.050 lb/MMBtu, if original limit could not be achieved because of condensable PM₁₀ emissions. The permit limit was increased to 0.03 lb/MMBtu based on stack testing.

Source: USEPA's RACT/BACT/LAER Clearinghouse and Technology Transfer Network at www.epa.gov/ttn/catc/dir1/natlcoal.xls. Cleco Rodemacher and Western Greenbrier from publicly available permits.

5.2 Circulating Fluidized Bed Boilers

The CFB boilers are sources of PM, PM₁₀, PM_{2.5}, SO₂, NO_x, CO, VOC, Pb, H₂SO₄, F⁻, trace elements, and volatile and semi-volatile organic compounds. Nitrogen oxide emissions will be controlled with the inherently low NO_x CFB combustor, staged combustion, and selective non-catalytic reduction (SNCR). Sulfur dioxide and other acid gas emissions will be controlled by injecting limestone into the CFB combustor and by a dry FGD system downstream of the boiler. A fabric filter will be used to control particulate and trace element emissions and also to provide secondary removal of acid gas emissions. The air emissions during the startup of the CFB will be limited to the mass emission rate set for each individual PSD pollutant, averaged over the duration of the startup. Thus, the steady state emissions of the boiler at full load will not be exceeded during startup or shutdown and the CEMS equipment will be recording emissions anytime during operation of the boiler. Although the pollution control technology systems cannot be operated during startup/shutdown, mass emission limits will be established consistent with CFB performance. Therefore, the control technology proposed for the Project during steady state operations represents BACT during startup and shutdown operations.

5.2.1 Nitrogen Oxides

Nitrogen oxide emissions from the CFB boilers will be controlled by the inherent design of the CFB combustor and SNCR capable of achieving emission levels of 0.07 lb/MMBtu on a 30-day rolling average at 75% load or greater, 0.11 lb/MMBtu on a 30-day rolling average between 50% and 75% load, and 0.15 lb/MMBtu on a 30-day average at 50% load or less (excluding startup, shutdown, and malfunction periods). **5.2.1.1 NO_x Formation and Control**

Nitrogen oxides formed during the combustion of coal are generally classified as either thermal NO_x or fuel-bound NO_x. Thermal NO_x is formed when elemental nitrogen in the combustion air is oxidized at the high temperatures in the primary combustion zone yielding nitrogen oxide (NO) and nitrogen dioxide (NO₂). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and increases exponentially with peak flame temperatures. Thermal NO_x from coal combustion can be effectively controlled by techniques that limit available oxygen or reduce peak flame temperatures in the primary combustion zone. Fuel-bound NO_x is formed by the oxidation of chemically bound nitrogen in the fuel. The rate of formation of fuel-bound NO_x is primarily a function of fuel bound nitrogen content, but is affected by fuel/air mixing.

Circulating fluidized bed combustion of coal produces lower NO_x emission rates than other coal combustion processes due to relatively low and uniform combustion temperatures, as well as controlled fuel/air mixing. Selective non-catalytic reduction, using ammonia or urea, is well suited to circulating fluidized bed combustion. With SNCR, ammonia is introduced into the boiler to react with NO_x in a temperature range of 1,600 F to 1,800 F range. Lower temperatures result in poor NO_x control and high ammonia slip, while higher temperatures result in an increase in NO_x emissions. All CFB combustors built to date either rely on the inherently low NO_x levels associated with the technology or use SNCR to further reduce NO_x emissions. Selective catalytic reduction has not been commercially demonstrated on a CFB combustor due to operational problems resulting from the extremely high solids loading in the flue gas and due to poisoning of the catalyst from calcium in the flue gas.

5.2.1.2 Recent BACT Determinations

A review of EPA's RBLC and recently issued permits identified the NO_x performance levels that may be achieved with various combinations of control technologies. The NO_x control technologies and associated performance levels for CFB boilers are summarized in Table 5-1. As shown in this table, several new CFB boilers have received permits within the last five years that impose NO_x emission limits ranging from 0.07 to 0.15 lb/MMBtu. The Project proposes to utilize the inherently low-NO_x combustor and SNCR to achieve a NO_x emission level of 0.07 lb/MMBtu on a 30-day rolling average at loads above 75% based upon the expected performance of the proposed combustion technology. This is equivalent to the most stringent NO_x emission limit established to date for similar installations in the country. Discussed below are the NO_x performance levels imposed on recently permitted CFB boilers that fire bituminous or waste coals in the country.

In Pennsylvania, the River Hill Power Company recently received a PSD permit for a proposed waste coal-fired CFB boiler equipped with SNCR with an allowable NO_x emission rate of 0.07 lb/MMBtu on a 30-day rolling average. Wellington Development also received a PSD permit late last year for a waste coal-fired CFB boiler with SNCR with an allowable NO_x emission rate of 0.10 lb/MMBtu on a 24-hour daily average and 0.08 lb/MMBtu on a 30-day rolling average. The Robinson Power Company received a PSD permit earlier last year for a waste coal-fired CFB boiler with SNCR with an allowable NO_x emission rate of 0.08 lb/MMBtu on a 30-day rolling average.

In Kentucky, the East Kentucky Power Company received PSD permits in 2002 for two coal-fired CFB boilers equipped with SNCR at the Spurlock Generating Station with allowable NO_x emission rates of 0.07 lb/MMBtu on a 30-day rolling average. In 2001, the Kentucky Mountain Power received a final PSD permit for a waste coal-fired CFB boiler equipped with SNCR with an allowable NO_x emission rate of 0.07 lb/MMBtu on a 30-day rolling average.

In Illinois, the Indec Elwood plant received a final PSD permit in 2003 for a CFB boiler firing bituminous coal with petroleum coke with an allowable NO_x emission rate of 0.10 lb/MMBtu on a 30-day average. The permit required an optimization program to determine a sustainable NO_x emission limit over time. In 2001, Enviropower's Benton Plant was issued a PSD permit for a CFB boiler fired with bituminous coal using only combustion controls with an allowable NO_x emission rate of 0.125 lb/MMBtu on a 30-day average. This permit required an optimization program to determine whether or not the unit can achieve an emission level of 0.07 lb/MMBtu. In Louisiana, Cleco Power received a permit with an allowable NO_x emission rate of 0.07 lb/MMBtu on a 30-day average, this permit includes a 12-month period when the allowable NO_x emission rate is 0.15 lb/MMBtu on a 30-day average. In West Virginia, the Western Greenbrier plant received a final PSD permit in 2006 for a CFB boiler firing waste coal with an allowable NO_x emission rate of 0.10 lb/MMBtu on a 30-day average.

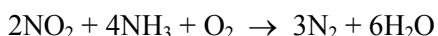
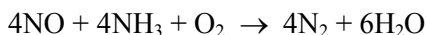
5.2.1.3 Alternative NO_x Control Technologies

The alternative NO_x control technologies available for coal-fired boilers include: staged combustion techniques, such as low-NO_x burners (LNB), flue gas recirculation (FGR), or over-fire air (OFA); selective non-catalytic reduction (SNCR); and selective catalytic reduction (SCR). These alternative NO_x

control technologies are evaluated below in terms of their application to CFB boilers fired with bituminous coal or waste coals.

Selective Catalytic Reduction

Selective catalytic reduction is a process that involves post-combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts NO_x to nitrogen and water by the following general reactions:



The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction to about 650 F. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. The SCR reactor would be located downstream of the economizer and upstream of the air preheater and the particulate control system. From the economizer outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air preheater. The SCR system for a pulverized coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primarily vanadium, platinum or titanium, (lower temperature) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia-NO_x ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550 to 800 F, which is significantly higher than for platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operating at temperatures above this range. Operating above the maximum temperature causes oxidation of ammonia to either ammonia sulfate or NO_x, thereby actually increasing NO_x emissions.

The sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide to sulfur trioxide (SO₃), which in turn combines with water to form H₂SO₄. At typical SCR operating temperatures, SO₃ and sulfuric acid react with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases cool and can lead to increased emissions of PM₁₀. Fouling may eventually lead to decreased NO_x reduction performance levels, increased system pressure drop, and decreased heat transfer efficiencies.

On pulverized coal-fired boilers, SCR can achieve NO_x control efficiencies as high as 90%. Therefore, application of SCR was examined as a potential BACT candidate based on technology transfer principles.

On new pulverized coal fired boilers, the SCR catalyst would have to be installed in a high dust location prior to the air pre-heater, where the gas temperature is close to 650 F. In a CFB, at this point where a comparable gas temperature is available, the flue gas contains very high concentrations of fly ash. The high dust loadings in the boiler backpass of the CFB are much higher than those experienced even on so-called “high dust” SCR installations on pulverized coal boilers. These high dust loadings in the CFB would cause rapid catalyst deactivation through two mechanisms: physical deactivation and chemical poisoning, thereby rendering the SCR ineffective for NO_x removal. For the proposed project, these problems would be especially severe due to the high ash content of the fuel. Physical deactivation of the catalyst occurs when the particulates in the flue gas physically mask or block the catalyst and prevent NO_x and NH₃ from contacting the catalyst. Chemical poisoning of the catalyst is caused by trace elements and alkaline substances that chemically attach to active pore sites. Calcium salts, and calcined limestone are chemical poisons that would be present in high concentrations in the CFB flue gas. Both of these reactions render SCR systems ineffective for NO_x control, and for these reasons SCR has never been installed on a CFB boiler in a high dust location. Consequently, SCR is generally not considered technically feasible for application to a CFB, and is particularly inapplicable to the Project because the Project’s expected fuels exacerbate both the technical deficiencies associated with use of SCR.

Physical and chemical deactivation of the catalyst might be prevented by operating the SCR as a low-dust system with the reactor located after the fabric filter. This is a so-called “tail-end SCR system. However, the flue gas temperature at this point is only 170 F, which is much too low for SCR. Even “low-temperature” catalysts require a temperature range of 425 to 450 F. There is no available research or developmental analyses or test equipment constructed that have evaluated the potential technical issues and obstacles that might be expected to be encountered in applying tail-end SCR to a CFB. Hence, any conclusions as to technical availability of tail-end SCR on a CFB are uncertain and not supported by any real data or information.

Although SCR has never been installed on a coal-fired CFB boiler after the final control device, if such a system were to be evaluated, there are several considerations to assess. . To minimize fuel consumption required for reheating, a gas-to-gas heat exchanger could be used. The heat exchanger would minimize the amount of reheat required to that required by the temperature approach between the inlet and outlet flue gas (in this configuration use of a low-temperature catalyst would be discarded as it would offer no advantage because the reheat requirement is dictated by practical limits on heat exchanger performance, not the SCR operating temperature).

Because a tail end SCR would require a system to reheat the flue gas, and thus system would entail different spacing and equipment configurations than expected for the CFB, such a system would incur large capital and operating expenses. To assess the cost effectiveness of a low-dust SCR system, the capital and annual operating costs were estimated for a low dust SCR system, including a gas-to-gas heat exchanger and distillate fuel oil to provide reheat. In this analysis, the SCR system is assumed to be capable of reducing NO_x emissions from an uncontrolled levels of 0.15 lb/MMBtu to a controlled level of 0.03 lb/MMBtu, although SCR has never been applied on a coal-fired CFB boiler. This assumption is for

a best case scenario where a tail-end SCR is assumed to be able to achieve the same 90% removal efficiency such systems have achieved, under different circumstances, on pulverized coal boilers. The total capital cost for the two units is estimated to be \$117 million, and the annual operating costs, \$46 million. Based on an annual NO_x emission reduction of 3,270 tons per year (tpy), the cost effectiveness of this control option is \$14,000 per ton of NO_x reduced. This level of costs is outside the range of costs accepted as BACT for NO_x. The cost analysis for the low-dust SCR system is provided in Appendix D.

There are also several adverse impacts associated with a low-dust SCR installed after the fabric filter. First, combustion of fuel oil will generate 10 tpy of PM₁₀, as well as SO₂, CO and VOC emissions. Second, the SCR system will oxidize some of the SO₂ in the flue gas, which will increase primary sulfuric acid and PM₁₀ emissions. Third, the energy consumption, even with gas-to-gas heat exchanger is high.

Because of technical feasibility issues and uncertainties, prohibitively high cost-effectiveness, and the associated economic penalty and other adverse environmental and energy impacts, a low-dust SCR system after the fabric filter is not considered BACT for the proposed CFB boilers.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction has been applied to a number of different types of combustion sources, including utility and industrial boilers fired with natural gas and oil, pulverized coal fired boilers, and coal-fired CFB boilers. The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and injected ammonia to produce gaseous nitrogen and water vapor. In an SNCR system, NO_x reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 to 1,900 °F. The factors affecting SNCR performance are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia will react with one mole of NO_x, forming elemental nitrogen and water. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a large amount of excess ammonia and essentially achieving low NO_x emissions at the expense of ammonia slip. Thus, for a given boiler configuration, there is a limit on the degree of NO_x reduction that can be achieved with SNCR, while maintaining acceptable levels of ammonia slip.

Many recently approved CFB boilers have been equipped with SNCR for NO_x control. In CFB boilers, the bed temperature and downstream flue gas temperature can be set by the operator to within a few degrees. The typical temperature of CFB flue gas leaving the bed and entering the hot cyclone is ideal for SNCR. Additionally, the reduction reagent is injected at the inlet to the hot cyclone, where the flue gas undergoes extreme turbulence. This cyclonic action ensures uniform reagent and NO_x concentration, thus maximizing ammonia-NO_x mixing. Pulverized coal-fired units have a much more limited furnace temperature window and poor lateral mixing, conditions which render SNCR less effective in these

applications. The SNCR technology has been applied to PC boilers more often to achieve 30% to 50% reductions in response to Reasonably Available Control Technology (RACT), because the technology can be retrofitted more readily than SCR. Due to mixing limitations and limited temperature window in which to react, SNCR is fundamentally less effective at controlling NO_x from PC units compared with CFB units. Because SNCR is the only NO_x control technology applied to coal-fired CFB boilers, it is considered representative of BACT.

Staged Combustion

A number of techniques have been employed to reduce the formation of NO_x by reducing peak flame temperature and/or starving the hottest parts of the flame for oxygen. By staging the combustion process, a longer, cooler flame results, which forms less NO_x. Staged combustion techniques include low-NO_x burners, flue gas recirculation, over-fire air, and burners out of service. A collateral impact of staged combustion is an increase in emissions of products of incomplete combustion including CO, VOC and unburned carbon (referred to as Loss on Ignition or LOI). Staged combustion can be applied to both PC and circulating fluidized bed boilers. For PC boilers, staged combustion can include low-NO_x burners, flue gas recirculation, and/or over-fire air. In a CFB boiler, staged combustion consists of introducing combustion air at different levels. The coal proposed for this project, however, is expected to have a high percentage of fines, which are expected to burn higher in the furnace in a hotter, more oxygen rich zone, producing more NO_x. The staged combustion air process will be used, but will have a limited effect on NO_x production due to coal fines.

5.2.1.4 Conclusions

Based on a review of available control technologies for NO_x emissions from a CFB, we conclude that the lowest sustainable NO_x emission rate that has been demonstrated in practice and can be expected to be achieved for the proposed CFB boilers burning bituminous coal or waste coals is .07 lb/MMBtu on a 30-day rolling average at 75% load or greater, 0.11 lb/MMBtu on a 30-day rolling average between 50% and 75% load, and 0.15 lb/MMBtu on a 30-day average at 50% load or less (excluding startup, shutdown, and malfunction periods). These emission levels are based on reliance on the expected performance of the CFB (inherent low levels of NO_x generated in CFB units), staged combustion, and the expected performance level of SNCR. No adverse economic, energy, or environmental impacts have been identified that would prevent the proposed project from continuously maintaining these NO_x emission levels. Accordingly, the proposed NO_x control technologies and associated emission levels represent BACT for the proposed CFB boilers. No cost analysis is necessary because the top feasible technology has been selected.

5.2.2 Sulfur Dioxide

The proposed facility is limited to burning the fuels available in the coal field region of Virginia by the provisions in the Electric Restructuring Bill passed by the Virginia legislature. The analysis of the available fuels specifies a need to utilize a 2.28% sulfur fuel. Sulfur dioxide emissions will be controlled by limestone injection into the boiler and a flash dryer absorber or comparable dry FGD system capable of achieving an emission level of 0.12 lb/MMBtu on a 24-hour average basis under all operating loads (excluding startup, shutdown, and malfunction periods).

5.2.2.1 SO₂ Formation and Control

Sulfur dioxide emissions are generated in fossil fuel-fired combustion units from the oxidation of sulfur present in the fuel. Approximately 98% of the sulfur in coal is emitted upon combustion as gaseous sulfur oxides, SO₂ and SO₃. Uncontrolled emissions of SO₂ are directly related to the fuel sulfur content, and not by the firing mechanism, boiler size, or operation. Many coal-fired boilers in the U.S. limit emissions of SO₂ through the use of low sulfur western coals, including Powder River Basin Coal. Compared with a higher sulfur eastern bituminous coal that may contain as much as 4% sulfur, burning western coal can reduce SO₂ emissions by approximately 70% to 90%. The selection of coal type and sulfur content, therefore, is an important aspect of the determination of BACT and needs to be considered in conjunction with add-on control alternatives when performing the top-down analysis. The Project is being developed in response to legislation, which requires the use of Virginia coal exclusively. Accordingly, the Project proposes to blend the available fuels that will result in a sulfur content in the design fuel going into the boiler of 2.28%, and a higher heating value of 7,782 Btu per pound (Btu/lb). This combination of sulfur content and heating value will result in maximum potential emissions, before control, of 5.9 lb/MMBtu.

The Project evaluated air jigging as a coal cleaning technique to further reduce the high sulfur content, the ash content and the Btu value of the Moss #3 waste coal found in the coal field region of Virginia. The waste material is not suitable for separation by air jigging and is deemed technically infeasible. The CFB boiler design is capable of efficiently burning low Btu, high ash fuels, while minimizing SO₂ emissions.

Generally, there are two types of control available for coal-fired boilers: *in-situ* combustion control (sorbent injection) and post-combustion control (flue gas desulfurization). *n-situ* control using limestone injection is used effectively in CFB boilers. This *in-situ* control may also be used in PC boilers by injecting limestone into the furnace; however, the level of control that is achievable is not comparable to the performance in a CFB boiler or to post-combustion SO₂ control systems. Post-combustion controls typically applied to PC boilers are a wet scrubbing system or spray dryer absorber using reagents such as lime, sodium bicarbonate, or magnesium oxide. Most CFB boilers, on the other hand, do not use post-combustion controls. Those CFBs with post combustion control have all used some type of dry control system, either spray dryer absorber or dry FGD system to achieve a combined SO₂ removal efficiency of 98%. Wet scrubbing has not been applied to a CFB boiler.

5.2.2.2 Recent BACT Determinations

A review of USEPA's RBLC and recently issued permits identified the SO₂ performance levels that may be achieved with various combinations of control technologies. The SO₂ control technologies and associated performance levels for CFB boilers are listed in Table 5-1. As shown in this table, several new CFB boilers have received permits within the last five years that impose SO₂ emission limits ranging from 0.02 to 0.60 lb/MMBtu. These performance levels, however, do not reflect the sulfur content of the coal or the SO₂ removal efficiency of the control system. Based on a limited number of permits, the SO₂ removal efficiency for CFB boilers firing bituminous or waste coal ranged from 92% to over 98% (see Table 5-2). The Project proposes to inject limestone into the CFB boilers to achieve an SO₂ emission level of 0.15 lb/MMBtu on a 3-hour average and 0.12 lb/MMBtu on a 24-hour average, which is equivalent to an SO₂ removal efficiency of approximately 98.0%. This proposed SO₂ performance level is within the range of the most stringent SO₂ emission limits established to date for CFB boilers burning high-sulfur bituminous coals and waste coal around the country.

Table 5-2: Summary of SO₂ Performance Levels for Circulating Fluidized Bed Boilers

Project	Size (MW)	Fuel	SO ₂ Limit (lb/MMBtu)	SO ₂ Removal (%) ^a
AES Puerto Rico Cogeneration Project	454	Bituminous Coal	0.022 (3-hour)	98.7
Robinson Power Beach Hollow	270	Waste Coal	0.245 (3-hour)	97.0
Wellington Development Greene Energy	525	Waste Coal	0.234 (3-hour) 0.156 (30-day)	98.0
River Hill Power	270	Waste Coal	0.274 (3-hour) 0.200 (30-day)	98.0
Enviropower Benton	500	Bituminous Coal	0.25 (30-day)	97.5 (design) 92.0 (minimum)
Montana-Dakota Utilities Westmoreland	175	Lignite Coal	0.038 (30-day)	98.9
Southern Montana Electric Highwood Generating	250	Sub-bituminous Coal	0.057 (1-hour)	97.5
NEVCO Energy Sevier Power	270	Sub-bituminous Coal	0.050 (24-hour) 0.022 (30-day)	90.0

^a The SO₂ removal efficiency is based on estimated performance cited in the USEPA RBLC. These are not necessarily permit limits.

AES Puerto Rico received a PSD permit for a proposed CFB boiler firing low-sulfur bituminous coal with an allowable SO₂ emission rate of 0.022 lb/MMBtu as a 3-hour maximum. This emission level is equivalent to an SO₂ removal efficiency of 98.7%. The estimated SO₂ removal efficiency, however, is based on the maximum allowable sulfur content of the bituminous coal of 1.0%, when in actuality the sulfur content is expected to be 0.75% or lower. Also, this facility burns a very consistent low-sulfur fuel mix. Similarly, Montana-Dakota Utilities received a PSD permit in 2005 for a lignite-fired CFB boiler with an allowable SO₂ emission rate of 0.038 lb/MMBtu on a 30-day rolling average, which is equivalent to an SO₂ removal efficiency of approaching 99%. Again this estimated SO₂ removal efficiency, however, is based on the maximum allowable sulfur content of the lignite fuel, when in actuality the sulfur content is expected to be much lower.

In Pennsylvania, the River Hill Power Company recently received a PSD permit for a proposed waste coal-fired CFB boiler with an allowable SO₂ emission rate of 0.274 lb/MMBtu as a 3-hour maximum and 0.200 lb/MMBtu on a 30-day rolling average. This is equivalent to an SO₂ removal efficiency of approximately 98%. Wellington Development also received a PSD permit late last year for a waste coal-fired CFB boiler with an allowable SO₂ emission rate of 0.234 lb/MMBtu on a 3-hour daily average and 0.156 lb/MMBtu on a 30-day rolling average, which is equivalent to an SO₂ removal efficiency of approximately 98%. The Robinson Power Company received a PSD permit earlier last year for a waste coal-fired CFB boiler with an allowable SO₂ emission rate of 0.245 lb/MMBtu as a 3-hour maximum, which is equivalent to an SO₂ removal efficiency of approximately 97%. In Louisiana, Cleco Power received a permit with an allowable SO₂ emission rate of 0.15 lb/MMBtu on a 30-day average, this permit includes a 12-month period when the allowable SO₂ emission rate is 0.20 lb/MMBtu on a 30-day average. In West Virginia, the Western Greenbrier plant received a final PSD permit in 2006 for a CFB boiler firing waste coal with an allowable SO₂ emission rate of 0.14 lb/MMBtu on a 3-hour average; this plant will fire coal with a maximum 1.47% sulfur content.

5.2.2.3 Alternative SO₂ Control Technologies

The alternative SO₂ control technologies available to further reduce SO₂ emission from the coal-fired boilers include flash dryer absorber (FDA), spray dryer absorber (SDA), and wet flue gas desulfurization (FGD). These alternative SO₂ control technologies are evaluated below in terms of their application to CFB boilers fired with bituminous coal or waste coal.

Wet Flue Gas Desulfurization

On pulverized coal fired boilers, the most frequently used SO₂ control method is wet flue gas desulfurization (FGD) technology using a wet limestone spray tower system. Typically, flue gas enters at the bottom of the absorber tower, continues vertically through the limestone/water spray, passes through a mist eliminator to control the re-entrained slurry drops, and then exits the tower. Limestone (calcium carbonate) reacts with the sulfur dioxide to form calcium sulfite. The calcium sulfite may then be oxidized to form calcium sulfate, to facilitate dewatering of the calcium salts. This can be achieved by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank.

To fully utilize the limestone, the slurry is re-circulated through the tower and a bleed stream is taken off for dewatering. The bleed stream can be dewatered using a variety of techniques, including thickeners, centrifuges and vacuum filters. The final slurry may contain 10 to 40% water by weight. Wet scrubbers can also utilize lime rather than limestone. Some of the lime (calcium oxide) becomes calcium hydroxide in water. The slurry of calcium hydroxide and lime is fed to the spray tower. Because the cost of limestone is much less than lime, the limestone alternative is much more common. This is especially the case for medium to high sulfur coals.

Although wet flue gas desulfurization has never been applied to a CFB boiler, this SO₂ control system might be technically feasible in some situations where adequate water supply is available. Therefore, the potential energy, environmental, and economic impacts of applying this technology to the proposed CFB

boiler were evaluated by means of the USEPA's CUECost Program (<http://www.epa.gov/ttn/catc/products.html#software>). An SO₂ removal efficiency of 90% assumed although the technical feasibility of achieving this performance level in this application is uncertain. Installing a wet scrubber for SO₂ control system would cause a significant increase in the project capital cost of \$77 million. Annualized cost for the wet scrubber, including labor, maintenance, reagents, electrical power and capital recovery, would be \$27.8 million. If the assumed SO₂ removal efficiency were achieved, the cost effectiveness would be \$8,100 per ton of SO₂ removed, which is considered cost prohibitive for the proposed CFB boilers. The results of the cost analysis are provided in Appendix D. It should be noted that this cost does not include costs to obtain a reliable water supply of the needed quality.

In order to minimize water consumption, the Project has already taken very significant measures in developing the conceptual design of the facility. These steps include the use of dry cooling and efforts to re-use as much water as possible within the facility. These measures have been taken by the Project due to limited water supplies in the area and due to historical concerns expressed regarding the ecological impact of water withdrawal in the area. Minimizing water consumption through the implementation of such conservation measures is viewed as an essential component of this Project. Due to the substantial amount of water that would be required to support wet FGD operations, it is not believed that sufficient water would be available for wet FGD. This method of sulfur dioxide removal is therefore considered infeasible for this application.

In addition, there would be significant environmental impacts associated with the disposal of the wet sludge generated by the wet scrubber. Energy impacts associated with wet scrubbing would be high as the system would require 9.5 MW of electricity or about 1.6% of the power plant net output.

Because wet scrubbing has never been applied to a CFB boiler and the energy, environmental, and economic impacts are significant, the addition of wet limestone scrubbing for SO₂ control for the CFB boilers is not considered BACT.

Spray Dryer Absorber

The spray dryer absorber (SDA) is located upstream of the particulate collection device. The flue gas passes through a spray dryer vessel where it encounters a fine mist of lime slurry. The lime slurry is injected into the spray dryer absorber through either a rotary atomizer or fluid nozzles. The moisture in the droplets evaporates and the lime reacts with the SO₂ in the flue gas to form insoluble calcium salts. The flue gas is cooled to approximately 18 to 30 F above the adiabatic saturation temperature of the flue gas. The calcium salts have a moisture content of approximately 2 to 3%, which drops to 1% before reaching the particulate control device. When a fabric filter is used as the particulate control device, it allows for further reaction of the lime captured in the filter media with the sulfur (and other acid gases) in the flue gas. This is due to the layer of porous filter cake on the surface of the filter that contains the reagent that all flue gas must pass through. This allows for increased efficiency of control of sulfuric acid mist, hydrogen chloride and mercury as compared to wet scrubbers. Spray dryer absorbers have been applied to both CFB boilers and PC boilers.

Flash Dryer Absorber

The flash dryer absorber (FDA) or dry FGD process is based on the absorption of SO₂ by a dry absorbent containing lime (CaO) or dry hydrated lime (Ca(OH)₂). Either of these absorbents may be used, as well as fly ash containing an appropriate amount of alkali. Water is added to the absorbent in a mixer prior to its introduction into the flue gas. After the activation/drying step, the dried recycle dust is separated from the flue gas in a fabric filter. From there the dust is again fed to the mixer, where make up lime can be added. Water is fed to the mixer in a quantity sufficient to maintain a constant outlet flue gas temperature. The FDA process is characterized by a very high recycle rate, maximizing the utilization of the reagent. The high recycle rate also means that there is a large surface area available for the rapid evaporation of water. Consequently, the volume of the reactor/dryer for the FDA process is an order of magnitude less than that for a conventional spray dryer technology. For a CFB boiler, hydrated lime addition to the recycle generally is not required due to the large amount of calcined limestone carried over from the CFB. Based on these considerations, the Project has decided to install a FDA or comparable dry FGD system downstream of the boiler to provide additional SO₂ removal for each CFB boiler.

5.2.2.4 Conclusions

The Project is proposing to limit SO₂ emissions to 0.12 lb/MMBtu on a 24-hour average under all operating loads (excluding startup, shutdown, and malfunction periods). For a coal blend having a heating value of 7,782 Btu per pound (Btu/lb) and a maximum sulfur content of 2.28%, these emission levels are equivalent to an SO₂ removal efficiency ranging from 97.5 to 98.0%. The Project will control SO₂ emissions by injecting limestone into the CFB combustor and installing an FDA or comparable dry FGD system downstream of the boiler. This control technology train is considered the top BACT control for SO₂ emissions from a CFB boiler. No further cost analysis is necessary because the top feasible technology is selected.

5.2.3 Carbon Monoxide Emissions

Carbon monoxide emissions from the CFB boilers will be controlled by good combustion practices capable of achieving an emission level of 0.15 lb/MMBtu on a 30-day rolling average above 75% load or 0.20 lb/MMBtu on a 30-day rolling at 75% or less (excluding startup, shutdown, and malfunction periods).

5.2.3.1 CO Formation and Control

Carbon monoxide is a product of incomplete combustion in any combustor. The formation of CO is controlled by providing adequate fuel residence time, excess oxygen, and high temperature in the combustion zone to ensure complete combustion. The CO emissions from CFB boilers are somewhat higher than those from pulverized coal boilers. These higher CO emissions are a result of the lower combustion temperatures found in CFB boilers, thereby resulting in slightly less complete combustion. Still, good combustion is achieved in the CFB boilers by ensuring good air-fuel mixing, uniform bed temperatures, long residence time, and good combustion control. It should be noted that, although lower combustion temperatures may slightly increase CO emissions, they also minimize NO_x formation and promote higher SO₂ collection in the CFB boiler.

5.2.3.2 Recent BACT Determinations

A review of EPA's RBLC and recently issued permits identified the CO performance levels that may be achieved with various combinations of control technologies. The control technologies and associated performance levels for CFB boilers are listed in Table 5-1. As shown in this table, several new CFB boilers have received permits within the last five years that impose CO emission limits ranging from 0.10 to 0.27 lb/MMBtu. However, those CFB units required to meet an NO_x emissions limit of 0.07 lb/MMBtu typically need only meet a CO emission limit of 0.15 lb/MMBtu or higher. This reflects the need to optimize combustion conditions to control both NO_x and CO emissions from CFB boilers. The Project proposes to employ good combustion practices to achieve a CO emission level of 0.15 lb/MMBtu, consistent with the CO emission limits established for units required to meet the most stringent NO_x emission limit of 0.07 lb/MMBtu. Discussed below are the most stringent performance levels imposed on recently permitted CFB boilers that fire waste coal or bituminous coal.

In Pennsylvania, Wellington Development received a PSD permit last year for a waste coal-fired CFB boiler with an allowable CO emission rate of 0.20 lb/MMBtu as a 1-hour daily maximum. The Robinson Power Company received a PSD permit earlier last year for a waste coal-fired CFB boiler with an allowable CO emission rate of 0.15 lb/MMBtu as a 1-hour daily maximum. In 2003, Reliant Energy's Seward Power Plant received a PSD permit for a waste coal-fired CFB boiler with an allowable NO_x emission rate of 0.15 lb/MMBtu as a 3-hour average. In Kentucky, the East Kentucky Power Company received PSD permits for two CFB boilers burning waste coal at the Spurlock Generating Station with allowable CO emission rates of 0.15 lb/MMBtu on a 30-day rolling average. In Louisiana, Cleco Power received a permit with an allowable CO emission rate of 0.10 lb/MMBtu on a 30-day average at full load, and 0.15 lb/MMBtu on a 30-day average at part load (75% load or less). The Cleco permit includes a 12-month period when the allowable CO emission rate is 0.15 lb/MMBtu on a 30-day average. In West Virginia, the Western Greenbrier plant received a final PSD permit in 2006 for a CFB boiler firing waste coal with an allowable CO emission rate of 0.20 lb/MMBtu on a 24-hour average.

5.2.3.3 Alternative CO Control Technologies

The alternative CO control technologies available for coal-fired boilers are combustion controls and oxidation catalyst systems. These alternative CO control technologies are evaluated below in terms of their application to CFB boilers fired with waste coal.

Oxidation Catalyst

Oxidation catalysts have been applied to fossil fuel combustion sources, such as combustion turbines fired with natural gas or low-sulfur fuel oil. This technology, however, has never been applied to coal-fired boilers. It is evaluated here to determine if it could be considered transferable technology for application to the proposed CFB boilers. In an oxidation catalyst system, the flue gas passes over a catalyst to lower the activation energy required to convert products of incomplete combustion (*i.e.*, CO and VOC) in the presence of oxygen, to carbon dioxide and water. The catalyst permits oxidation of the reactant species at lower gas temperatures and residence times than would be required for uncatalyzed oxidation.

The catalyst would have to be located at a point where the gas temperature is within an acceptable range. The effective temperature range for CO oxidation is between 600 °F and about 1,000 °F. Catalyst non-selectivity is a problem for sulfur containing fuels such as coal. Catalysts promote oxidation of SO₂ to SO₃, as well as CO to CO₂. The amount of SO₂ conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO₃ can be minimized to 5% of inlet SO₂. This level of conversion would result in a collateral increase in H₂SO₄ emissions, which could result in unacceptable amounts of corrosion to the fabric filter baghouse, air preheater, ductwork, and stack.

Oxidation catalysts are known to be extremely sensitive to potential masking, blinding or poisoning due to trace metals in the flue gas. While natural gas or fuel oil contains essentially no trace metals, coal contains many of such trace metals within the inert fraction referred to as fly ash. Trace metal concentrations are highly variable even from in coal taken within the same mine or seam. There is no empirical evidence available to show that oxidation catalyst technology would actually work with coal-fired boilers or, if so, how the trace metals would ultimately affect the life of the catalyst. Due to the high particulate loading, variable trace element concentrations, and high SO₂ concentrations, oxidation catalyst systems are considered technically infeasible for application to the proposed CFB boilers.

Combustion Controls

Combustion control refers to controlling emissions of CO through the design and operation of the boiler in a manner so as to limit CO formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also tend to reduce emissions of VOC, as well as CO. The use of waste coal with a high percentage of fines, complicates the tuning of these factors due to the variability expected in the waste fuel. In addition, this process must be optimized with the efforts to reduce NO_x emissions, which may increase when steps are taken to lower CO are taken.

5.2.3.4 Conclusions

Based on a review of available control technologies for CO emissions from CFB boilers, we conclude that the lowest sustainable CO emission rate that has been demonstrated in practice and can be guaranteed for the proposed CFB boilers burning bituminous coal is 0.15 lb/MMBtu on a 30-day rolling average above 75% load or 0.20 lb/MMBtu on a 30-day rolling average at 75% or less (excluding startup, shutdown, and malfunction periods). The only practical means of achieving this CO emission level is good combustion practices, which must not only minimize the formation of CO, but also limit the formation of NO_x. Given the need to optimize NO_x and CO emissions, a CO emission rate of 0.15 lb/MMBtu on a 30-day rolling average represents BACT for the proposed CFB boilers. No cost analysis is necessary because the top feasible technology is selected.

5.2.4 Particulate Matter

Particulate emissions from the CFB boilers will be controlled by a fabric filter capable of achieving emission levels of 0.030 lb/MMBtu of total (filterable and condensable) PM₁₀ and 0.010 lb/MMBtu of filterable PM₁₀ under all operating loads.

5.2.4.1 Particulate Formation and Control

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, coal properties and emission controls. Particulate matter will be emitted from the circulating fluidized bed waste coal-fired boilers as a result of entrainment of incombustible inert matter (fly ash) in the combustion gases, the carry-over of calcium salts and calcined limestone from the circulating bed, and the formation of condensable substances, such as acid gases and ammonium salts, downstream of the CFB. Both particulate matter (PM) and particulate matter smaller than 10 microns (PM₁₀) require the application of BACT. Particulate matter includes total filterable particulate matter as determined by USEPA Method 5 or 17. PM₁₀ includes filterable particulate matter smaller than 10 microns as determined by USEPA Method 201 or 201A, and condensable particulate matter as determined by USEPA Method 202.

USEPA Method 202 has shown notable uncertainty in the determination of condensable particulate matter. Minor variations in how the test is performed have caused significant test result discrepancies. Several permits have been issued that do not require the testing of condensable particulate matter. Because of the difficulties with the test method, and because the condensable particulate emissions may not be affected by standard post-combustion control, it may not be possible to obtain a vendor guarantee for condensable particulate emissions.

5.2.4.2 Recent BACT Determinations

A review of EPA's RBLC and recent permit identified the PM/PM₁₀ performance levels that may be achieved with various combinations of control technologies. The control technologies and associated performance levels for CFB boilers are listed in Table 5-1. As shown in this table, the USEPA and responsible state agencies limited the emissions of filterable PM or PM₁₀ only from coal-fired boilers. More recently, these agencies have established emission limits not only for filterable PM/PM₁₀, but also

for total (filterable and condensable) PM₁₀. These permits include emission limits on filterable PM/PM₁₀ ranging from 0.011 to 0.030 lb/MMBtu, as well as emissions limits on total PM₁₀ ranging from 0.015 to 0.050 lb/MMBtu. The Project proposes to employ a fabric filter to limit filterable PM emissions to 0.01 lb/MMBtu, and total PM₁₀ to 0.03 lb/MMBtu, within the range of allowable emissions established for recently approved CFB boilers. Discussed below are the more stringent PM/PM₁₀ emission limits established for CFB boilers that fire waste coal or bituminous coal.

AES Puerto Rico received a PSD permit for a CFB boiler firing low-sulfur bituminous coal with an allowable filterable PM₀ emission rate of 0.015 lb/MMBtu and a total PM₁₀ emission rate of 0.015 lb/MMBtu. Because data on condensable PM₁₀ emissions from fluidized bed boilers are not readily available, however, the USEPA recognized that there is a possibility that the actual condensable portion of PM₁₀ may prevent compliance with the allowable total PM₁₀ emission rate. In the event that this limit cannot be met because of condensable PM₁₀, the USEPA included a provision in the permit that would allow an adjustment to the allowable total PM₁₀ emission rate up to a limit not to exceed 0.050 lb/MMBtu. Ultimately, the PM₁₀ emission limit was increased to 0.030 lb/MMBtu following compliance testing.

In Pennsylvania, the River Hill Power Company recently received a PSD permit for a proposed waste coal-fired CFB boiler limiting filterable PM emissions to 0.030 lb/MMBtu and condensable PM₁₀ emissions to 0.012 lb/MMBtu. The limit was subsequently revised to 0.05 lb/MMBtu. In North Dakota, Montana-Dakota Utilities received a PSD permit for a CFB boiler burning lignite coal limiting filterable PM emissions to 0.0167 lb/MMBtu and total PM₁₀ emissions to 0.0275 lb/MMBtu. Similarly, Southern Montana Electric received a PSD permit for a CFB boiler burning sub-bituminous coal limiting filterable PM emissions to 0.012 lb/MMBtu and total PM₁₀ emissions to 0.026 lb/MMBtu. In Louisiana, Cleco Power received a permit with an allowable filterable PM emission rate of 0.011 lb/MMBtu; this permit includes a 12-month period when the allowable filterable PM emission rate is 0.015 lb/MMBtu. The Cleco permit does not limit condensable particulate. In West Virginia, the Western Greenbrier plant received a final PSD permit in 2006 for a CFB boiler firing waste coal with an allowable filterable emission rate of 0.015 lb/MMBtu on a 30-day average, and a total PM₁₀ emission rate of 0.030 lb/MMBtu on a 30-day average.

5.2.4.3 Alternative Particulate Control Technologies

Fabric Filters

In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing particles in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges or, most commonly, bags. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Groups of bags are placed in isolable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

Practical application of fabric filters requires the use of a large fabric area in order to avoid an unacceptable pressure drop across the fabric. Baghouse size for a particular unit is determined by the choice of air-to-cloth ratio, or the ratio of volumetric air flow to cloth area. The selection of air-to-cloth ratio depends on the particulate loading, particle characteristics, and the cleaning method. A high particulate loading will require the use of a larger baghouse in order to avoid forming too heavy a dust cake, which would result in an excessive pressure drop.

Pulse-jet fabric filtration is the preferred cleaning method because it can treat high dust loadings, operate at constant pressure drop, and occupy less space than other types of fabric filters. Pulse-jet cleaned fabric filters can only operate as external cake collection devices. The bags are closed at the bottom, open at the top, and supported by internal retainers, called cages. Particulate-laden gas flows into the bag, with diffusers often used to prevent oversized particles from damaging the bags. The gas flows from the outside to the inside of the bags, and then out the gas exhaust. The particles are collected on the outside of the bags and drop into a hopper below the fabric filter.

Fabric filters in general provide the highest collection efficiencies for both coarse and fine particulates and are relatively insensitive to fluctuations in gas stream conditions. In addition, the efficiency and pressure drop are relatively unaffected by large changes in inlet dust loadings for continuously cleaned filters. Most importantly, fabric filters support secondary SO₂ removal in order to achieve the very low SO₂ emission level of 0.15 lb/MMBtu. Because of the secondary SO₂ removal, the proposed CFB boiler will have a very high inlet particulate loading due to the high ash content of the fuel, the gypsum product formed by the sulfur capture in the furnace and the unreacted limestone injected into the furnace.

Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector plates. The collector plates are periodically knocked or rapped by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The collection hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust-handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner.

The voltage applied to the electrodes causes the gas between the electrodes to break down electrically, an action known as a “corona.” The electrodes are usually given a negative polarity because a negative corona supports a higher voltage than does a positive corona before sparking occurs. The ions generated in the corona follow electric field lines from the wires to the collecting plates. Therefore, each wire establishes a charging zone through which the particles must pass. As larger particles absorb many times more ions than small particles, the electrical forces are much stronger on larger particles.

Certain types of losses affect control efficiency. The rapping that dislodges the accumulated layer also releases some of the particles back into the gas stream. These re-entrained particles are then collected

again in later sections, but the particles re-entrained in the last section are not collected and escape the unit. Further, part of the gas may flow around the charging zones through the clearances required for non-electrified internal components at the top of the ESP. This is called “sneakage” and places an upper limit on the collection efficiency.

Another major factor in the performance is the resistivity of the collected material. Because the particles form a continuous layer on the ESP plates, all the ion current must pass through the layer to reach the ground plates. This current creates an electric field in the layer, which can become strong enough to cause local electrical breakdown known as “back corona.” Back corona is prevalent when the resistivity of the layer is high, that reduces the collection ability of the unit because of the severe back corona causes difficulties in charging the particles. At low resistivities, the particles are held on the plates so loosely that particle re-entrainment becomes much more severe.

Compared to fabric filters, ESPs are generally less effective at controlling fine particulate and are incapable of secondary control of other pollutants, such as acid gases or mercury. In general, ESPs are not suited for use in combustion units that are highly variable because they are very sensitive to fluctuations in gas stream conditions. In addition, certain particulates are difficult to collect due to extremely high or low resistivity characteristics.

5.2.4.4 Conclusions

Based on a review of recently issued permits, fabric filtration has been applied to control PM/PM₁₀ emissions from CFB boilers, as well as to provide secondary control of SO₂ and other acid gases. These permits also established emission limits for filterable PM/PM₁₀ ranging from 0.010 to 0.030 lb/MMBtu. The Project proposes to limit total PM₁₀ emissions to 0.03 lb/MMBtu and filterable PM₁₀ to 0.01 lb/MMBtu. Based on the application of fabric filtration, the proposed control strategy is considered representative of BACT. No cost analysis is necessary because the top feasible technology is selected.

5.2.5 Volatile Organic Compounds

Volatile organic compounds from the CFB boilers will be controlled by good combustion practices capable of achieving an emission level of 0.005 lb/MMBtu under all operating loads.

5.2.5.1 VOC Formation and Control

Volatile organic compounds are also emitted from coal-fired boilers as a result of incomplete combustion of the fuel. Control of incomplete combustion is accomplished in the same way CO emissions are controlled: by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

5.2.5.2 Recent BACT Determinations

A review of EPA's RBLC and recently issued permits identified the VOC performance levels that may be achieved with various combinations of control technologies. The control technologies and associated performance levels for CFB boilers are listed in Table 5-1. As shown in this table, several new CFB

boilers have received permits within the last five years that impose VOC emission limits ranging from 0.0026 to 0.013 lb/MMBtu. The Project proposes to limit the VOC emissions from the CFB boilers to 0.005 lb/MMBtu, within the range of VOC emission limits established for recently permitted CFB units around the country. The proposed VOC emissions level is based on the manufacturer's guarantee for the CFB boiler; the manufacturer is unable to guarantee the lower VOC emission levels due to the limited data available on VOC emissions from CFB boilers. Discussed below are the most stringent VOC emission limits established for CFB boilers that fire waste coal or bituminous coal.

In Pennsylvania, the River Hill Power Company recently received a PSD permit for a proposed waste coal-fired CFB boiler limiting VOC emissions to 0.005 lb/MMBtu. Wellington Development received a PSD permit for a waste coal-fired CFB boiler last year limiting total VOC emissions to 0.006 lb/MMBtu. The Robinson Power Company received a PSD permit for a waste coal-fired CFB boiler limiting VOC emissions to 0.005 lb/MMBtu. In 2003, Reliant Energy's Seward Power Plant received a PSD permit for a waste coal-fired CFB limiting VOC emissions to 0.005 lb/MMBtu. In Kentucky, the Kentucky Mountain Power Company received PSD permits for two CFB boilers burning waste coal at the Spurlock Generating Station limiting VOC emissions to 0.0072 lb/MMBtu. In 2001, the East Kentucky Power also received a PSD permit for a waste coal-fired CFB boiler limiting filterable PM emissions to 0.0026 lb/MMBtu.

5.2.5.3 Alternative VOC Control Technologies

Combustion control refers to controlling emissions of VOC through the design and operation of the boiler in a manner that limits VOC formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also have the by-product of reducing the emissions of CO. Circulating fluidized bed coal-fired boilers are designed specifically for efficient fuel combustion with thorough mixing and residence time at temperature, plus staged combustion. This level of combustion control represents BACT for the proposed boilers.

5.2.5.4 Conclusion

The only practical means of controlling VOC emissions from coal-fired boilers are good combustion practices. Combustion controls will be used to optimize the emissions of both VOC and NO_x. The Project is proposing a BACT limit of 0.005 lb/MMBtu, which is as low as the most recent permits for coal-fired CFB boilers.

5.2.6 Sulfuric Acid Mist

Sulfuric acid mist is generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. The amount of SO₂ that is oxidized to H₂SO₄ may be affected by trace metal catalysis. The Project will control sulfuric acid mist by limestone injection in the fluidized bed, the use of an FDA system or a comparable dry FGD system, and fabric filtration. The Project proposes to limit H₂SO₄ emissions to 0.005 lb/MMBtu as BACT. This proposed emission limit is in the range of recent applications (Greene Energy

and Reliant Seward both proposed 0.006 lb/MMBtu). No alternative H₂SO₄ control technologies have been identified for the CFB boiler.

5.2.7 Fluorides

Fluoride emissions are generated in fossil fuel-fired sources from the oxidation of fluorine present in the fuel. For the CFB boilers, the same acid gas control technology used for SO₂ and H₂SO₄ will control fluoride emissions. The Project is proposing a fluoride emission rate (as HF) of 0.0023 lb/MMBtu as BACT based on an assumed concentration of fluorine in the coal of 860 ppm and an estimated acid gas control efficiency of 98%. The proposed emissions level is in the range of recent applications (Greene Energy proposed 0.0014 lb/MMBtu). No alternative H₂SO₄ control technologies have been identified for the CFB boiler.

5.2.8 Hydrogen Chloride

Hydrogen chloride (HCl) emissions are generated in fossil fuel-fired sources from the oxidation of chlorine present in the fuel. For the CFB boilers, the same acid gas control technology used for SO₂ and H₂SO₄ will control HCl emissions. The Project is proposing an HCl emission rate of 0.0066 lb/MMBtu as BACT based on an assumed concentration of chlorine in the coal of 1,000 ppm and an estimated acid gas control efficiency of 95% as BACT. No alternative HCl control technologies have been identified for the CFB boiler.

5.2.9 Trace Metals

Trace metal emissions (including beryllium emissions) from fossil fuel-fired sources result from the impurities present in the fuel. Because non-volatile trace metals are emitted as solid particulate from coal-fired boilers, it is already included in the total PM₁₀ emissions from the CFB boiler. Therefore, the proposed PM/PM₁₀ control device and associated performance levels also represent BACT for non-volatile trace metal emissions from the CFB boilers.

5.2.10 Mercury

Mercury emissions are generated from chemical components found naturally in coal. What limited data is available on mercury emissions from CFB boilers firing bituminous coal indicate that CFB technology, acid gas control system, and fabric filtration system will result in control of mercury emissions. The Project proposes to meet an annual mercury limit of 72 lb/yr, which is below the New Source Performance Standards.

5.2.11 Volatile and Semi-Volatile Organic Compounds

Volatile and semi-volatile organic compounds are emitted as products of incomplete combustion, and are generally included in VOC emissions, above. The combustion practices that represent BACT for VOC control also represent BACT for volatile and semi-volatile organic compounds.

5.2.12 Ammonia

Ammonia emissions result from excess ammonia being injected in the SNCR system to control NO_x emissions from the CFB boilers. The Project proposes to optimize the operation of the SNCR system to minimize the NO_x emissions, while preventing excessive ammonia slip.

5.3 Auxiliary Boiler

The auxiliary boiler is a source of the criteria pollutants NO_x, SO₂, CO, PM/PM₁₀, and VOC. Nitrogen oxide emissions will be controlled by low-NO_x burners. Sulfur dioxide will be controlled by firing distillate fuel oil with a maximum sulfur content of 0.2% or less.

5.3.1 Nitrogen Oxides

The auxiliary boiler will be equipped with low-NO_x burners (and possibly flue gas recirculation, depending on the final boiler vendor) to limit NO_x emissions to 0.12 lb/MMBtu. To further reduce NO_x emissions from the auxiliary boiler, two types of add-on NO_x controls could be applied to the auxiliary boiler, SCR or SNCR. An analysis of these two control technologies is provided below.

Selective Catalytic Reduction

Selective catalytic reduction involves the post-combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with nitrogen oxides on the surface of the catalyst to form nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. A fixed bed reactor is applied to combustion units with little or no particulate matter present in the flue gas, such as the exhaust gas for the proposed auxiliary boiler.

Based on USEPA cost data found in *Alternative Control Techniques Document* for NO_x emissions from *Industrial Commercial Institutional Boilers* (EPA-453/R-94-022), the uninstalled equipment cost for SCR applied to oil-fired package boilers is approximately \$2,400/MMBtu. This includes the catalyst, reactor, ammonia delivery, and control system, and boiler modification necessary to accommodate the SCR reactor. Using EPA cost factors, the total installed capital cost of an SCR system would be approximately \$829,000. The annual costs, including the fixed capital charges and operating costs, would be approximately \$290,000.

Assuming 90% removal, the annual reduction in NO_x emissions would be approximately 41 tons resulting in a control cost of approximately \$7,100 per ton of NO_x reduction. This is not considered cost effective for NO_x control. Therefore, SCR was eliminated from further consideration as economically infeasible as BACT for the auxiliary boiler. The cost analysis for SCR applied to the auxiliary boiler is summarized in Appendix D.

Selective Non-catalytic Reduction

Selective non-catalytic reduction relies on injecting ammonia or urea compounds into the exhaust gas at a temperature ranging from 1,600 to 1,900 F. At this temperature, NO_x and ammonia react without a catalyst, reducing NO_x to water and nitrogen. Because there is no catalyst, the conversion of NO_x to water and nitrogen is dependent upon the residence time within the optimum reaction temperature window. Adequate mixing of the reducing agent with the exhaust gas is another key to success.

Package boilers fired with distillate fuel oil generally have a temperature profile in which the temperature drops from approximately 2400 F to 500 F over a very short distance. Because of the compact design, which is typical of package boilers, the exhaust gas does not maintain suitable temperatures for a sufficient duration to allow for reaction of NO_x with NH₃. Given the short residence time at the optimum reaction temperature within the boiler and the low uncontrolled emission rate (0.12 lb/MMBtu), the efficiency of an SNCR system will be minimal.

Most SNCR operating experience exists on larger utility boilers, not on smaller package boilers fired with natural gas or distillate fuel oil. Consequently, SNCR is not considered technically feasible for package boilers due to the lack of demonstrated experience and inadequate residence time at the required reaction temperature. Therefore, SNCR is therefore not considered technically feasible as BACT for the auxiliary boiler.

Conclusions

The proposed auxiliary boiler will have a maximum heat input of 190 MMBtu/hr and will be fired with distillate fuel oil with a sulfur content of 0.2% by weight. The Project will limit operation of the auxiliary boiler 4,000 hours per year (hr/yr). The auxiliary boiler will be equipped with low-NO_x burners to limit NO_x emissions to 0.12 lb/MMBtu. Given the lack of experience with add-on controls on oil-fired package boilers, the proposed control technologies and associated performance levels are considered BACT for the auxiliary boiler.

5.3.2 Sulfur Dioxide

The Project will include an auxiliary boiler that will have a maximum heat input of 190 MMBtu/hr and will be fired with distillate fuel oil with a sulfur content of 0.2% by weight. The Project will also limit operation of the auxiliary boiler 4,000 hr/yr. Although the boiler could be fired with transportation grade fuel oil with a sulfur content of 0.05% by weight, it is not certain that such low-sulfur fuel oil would be readily available in this remote part of the state in the quantities required for the Project. Further, it is not clear what the price would be for low-sulfur fuel oil and hence what the cost would be for SO₂ control. Regardless, the Project will continue to investigate the availability and price of low-sulfur fuel oil to determine whether it would prove cost effective to control SO₂ emissions from the auxiliary boiler. The use of distillate fuel and the restriction in operations, therefore, are considered BACT for the auxiliary boiler.

5.3.3 Carbon Monoxide

Carbon monoxide emissions from the auxiliary boiler will be controlled using good combustion practices and firing distillate fuel oil. The operation of the auxiliary boiler will also be limited to 4,000 hr/yr. Although oxidation catalysts have been applied to oil-fired boilers and combustion turbines, there are no known installations of oxidation catalysts on limited use package boilers. Based on the lack of operating history, a CO oxidation catalyst is not considered representative of BACT. Therefore, the use of distillate fuel oil combined with good combustion practices are considered BACT for CO emissions from the auxiliary boiler.

5.3.4 Particulate Matter

Particulate emissions from the auxiliary boiler will be controlled using good combustion practices and firing low-sulfur fuel oil. The operation of the auxiliary boiler will also be limited to 4,000 hr/yr. Although add-on particulate control devices have been applied to large-scale oil-fired boilers, there are no known installations of particulate control devices on package boilers, much less limited use package boilers fired with low-sulfur oil. Based on the lack of operating history, add-on controls are not considered representative of BACT. Therefore, good combustion practices is considered BACT for PM/PM₁₀ emissions from the auxiliary boiler.

5.3.5 Volatile Organic Compounds

Volatile organic compound emissions from the auxiliary boiler will be controlled using good combustion practices. The operation of the auxiliary boiler will also be limited to 4,000 hr/yr. Although oxidation catalysts have been applied to oil-fired boilers and combustion turbines, there are no known installations of oxidation catalysts on limited use package boilers. Based on the lack of operating history, oxidation catalysts are not considered available for package boilers. Therefore, good combustion practices are considered BACT for VOC emissions from the auxiliary boiler.

5.4 Emergency Diesel Generators and Emergency Fire Pump

The emergency diesel generator and emergency diesel fire pump are sources of the criteria pollutants NO_x, SO₂, CO, PM/PM₁₀, and VOC. Nitrogen oxide emissions will be controlled by means of ignition retard. Sulfur dioxide emissions will be controlled by firing ultra-low sulfur diesel (ULSD) fuel oil with a maximum sulfur content of 15 ppmw. The emergency diesel generator and emergency diesel fire pump will comply with the NSPS under 40 CFR Subpart IIII.

5.4.1 Nitrogen Oxides

The Project includes an emergency diesel generator and emergency diesel fire pump. The Project will limit operation of the emergency diesel engines to 500 hr/yr each. Routine operation for each of these engines typically will not exceed 52 hours per year for testing and maintenance. The NO_x emissions from the engines during operation will be controlled by ignition timing retard and firing only low-sulfur distillate fuel oil.

The USEPA evaluated available add-on controls (such as SCR) and combustion controls (such as ignition timing retard) for the control of NO_x emissions from diesel engines in its Alternative Control Technology (ACT) Document. The USEPA concluded that add-on controls are not cost effective for “emergency diesel engines that operate less than 500 hours/year.” Therefore, BACT for NO_x emissions from these emergency diesel engines is using ignition timing retard, firing low-sulfur fuel oil, and restricting operations to less than 500 hours per year.

5.4.2 Sulfur Dioxide

The emergency diesel generator and an emergency diesel fire pump will be fired with ULSD fuel oil with a maximum sulfur content of 15 ppmw. The Project will limit operation of the emergency diesel engines to 500 hr/yr each. Routine operation for each of these engines typically will not exceed 52 hours per year for testing and maintenance. The use of low-sulfur fuel and restriction in operations are considered BACT for SO₂ emissions from the emergency diesel generator and emergency diesel fire pump.

5.4.3 Carbon Monoxide

Carbon monoxide emissions from the emergency diesel generator and emergency diesel fire pump will be controlled through good combustion practices and firing low-sulfur fuel oil. The operation of the emergency diesel engines will be limited to 500 hr/yr each. Based on review of recent permits, add-on controls for CO emissions have never been applied to emergency engines that operate less than 500 hours/year. Combustion controls and limited operating hours, therefore, are considered representative of BACT for CO emissions from the emergency diesel generator and diesel fire pump.

5.4.4 Particulate Matter

Particulate emissions from the emergency diesel generator and emergency diesel fire pump will be controlled through good combustion practices and firing low-sulfur fuel oil. The operation of the emergency diesel engines will be limited to 500 hr/yr each. Based on review of recent permits, add-on controls for PM/PM₁₀ emissions have never been applied to diesel engines, much less emergency engines that operate less than 500 hours/year. Combustion controls and limited operating hours, therefore, are considered representative of BACT for PM/PM₁₀ emissions from the emergency diesel generator and diesel fire pump.

5.4.5 Volatile Organic Compounds

Volatile organic compound emissions from the emergency diesel generator and emergency diesel fire pump will be controlled through good combustion practices. The operation of the emergency diesel engines will be limited to 500 hr/yr each. Based on review of recent permits, catalysts have never been applied to emergency engines that operate less than 500 hr/yr. Combustion controls and limited operating hours, therefore, are considered representative of BACT for VOC emissions from the emergency diesel generator and diesel fire pump.

5.5 Fuel Oil Storage Tanks

The only petroleum storage tanks on site are the 168,000-gallon primary fuel oil storage tank, the 1,640-gallon day tank for the emergency diesel generator, and the 350-gallon day tank for the emergency diesel fire pump. The VOC emissions from these tanks are extremely low primarily due to the low vapor pressure of No. 2 distillate fuel oil of less than 0.0001 psia. In addition, the storage tanks will be equipped with conservation vents to minimize breathing losses. Due to the limited annual fuel usage, the VOC losses from these fuel oil storage tanks will be about 0.02 ton/yr.

5.6 Material Handling Equipment

The other potential sources of PM/PM₁₀ emissions are material handling processes for the coal, ash, limestone, and miscellaneous materials. The Project will include equipment for the handling, processing, and transfer of coal, limestone, bed ash, fly ash, and supplemental fuels. Most material processing equipment will be entirely enclosed. Any vents from these enclosures will employ fabric filters with a guaranteed outlet grain loading of 0.005 gr/acf. Enclosing all of the material processing equipment through fabric filters represents the highest level of PM/PM₁₀ control available and represents BACT.

The fugitive sources that will not be entirely enclosed are coal and limestone delivery at the truck and railcar unloading stations, load-out from the bed ash and fly ash silos, transfer points for coal and limestone handling activities, bulldozing operations at the coal and limestone reclaim areas and the CCB storage area, and wind erosion from open piles. The material transfer and storage operations will use a combination of controls, including partial enclosures and/or dust suppression techniques, to minimize fugitive particulate emissions. These control measures are considered BACT for potential PM/PM₁₀ emissions from the material handling and processing equipment.

Fugitive dust emissions will be generated by vehicular traffic along plant roadways, primarily truck travel for the delivery of coal and limestone and the disposal of bed ash and fly ash. To minimize these fugitive dust emissions, all CFB plant roadways will be paved with the exception of the road to the CCB storage area. Fugitive dust mitigation measures, such as road wetting (unless prohibited by freezing conditions), will also be employed to further reduce emissions. Paving plant roadways and employing dust suppression techniques is considered BACT for these potential fugitive dust emissions.

5.7 Summary of BACT Emissions

The proposed BACT emissions levels for the CFB boilers and ancillary equipment are summarized in Tables 5-3 and 5-4, respectively.

Table 5-3: Proposed BACT Emission Limits for the CFB Boilers

Pollutant	Emission Limitation(s)	Control Technology
NO _x	see note a	CFB Combustion and SNCR
SO ₂	0.12 lb/MMBtu (24-hour daily average)	Limestone Injection and Fabric Filter
CO	see note b	Good Combustion Practices
VOC	0.005 lb/MMBtu (annual 3-hour test)	Good Combustion Practices
Total PM/PM ₁₀	0.030 lb/MMBtu (annual 3-hour test)	Fabric Filter
Filterable PM/PM ₁₀	0.010 lb/MMBtu (annual 3-hour test)	Fabric Filter
H ₂ SO ₄	0.005 lb/MMBtu (annual 3-hour test)	Limestone Injection and Fabric Filter
HF	0.0023 lb/MMBtu (annual 3-hour test)	Limestone Injection and Fabric Filter
Hg	1.3 x 10 ⁻⁶ lb/MWh	Fabric Filter CFB system co-benefit

^a Dominion is proposing 30-day rolling average emission limit for NO_x based on 0.07 lb/MMBtu above 75% load, 0.11 lb/MMBtu between 50% and 75% load, and 0.15 lb/MMBtu below 50% load.

^b Dominion is proposing 30-day rolling average emission limit for CO based on 0.15 lb/MMBtu above 75% load, and 0.2 lb/MMBtu below 75% load.

Table 5-4: Proposed BACT Emission Limits for Ancillary Equipment

Pollutant	Auxiliary Boiler	Emergency Diesel Generators	Emergency Diesel Fire Pump
NO _x	0.12 lb/MMBtu	0.82 lb/MMBtu	0.002 lb/MMBtu
SO ₂	0.20 lb/MMBtu	0.002 lb/MMBtu	1.42 lb/MMBtu
CO	0.080 lb/MMBtu	0.82 lb/MMBtu	0.82 lb/MMBtu
VOC	0.016 lb/MMBtu	0.01 lb/MMBtu	0.01 lb/MMBtu
PM/PM ₁₀	0.032 lb/MMBtu	0.024 lb/MMBtu	0.05 lb/MMBtu

ATTACHMENT 2

Attachment 2 - CFB Boilers													
Project	State	Size (MW)	Permit Status	Fuel	Heating Value (Btu/lb)	Sulfur Content	Ash Content (%)	PM limit (lb/MMBtu) ^a	SO ₂ limit (lb/MMBtu)	NO _x limit (lb/MMBtu)	CO limit (lb/MMBtu)	VOC limit (lb/MMBtu)	Control Technologies ^b
Enviropower Benton	IL	500	07/03/01 (Final Permit)	Bituminous Coal	4,000 Nominal	4% (wt) Nominal	N.A.	0.015 (Filt.PM)	0.25 (30-day)	0.125(30-day)	0.27 (30-day)	0.007 (3-hr)	SNCR, LI, FF GCP
East Kentucky Power Spurlock 3		300	08/04/02 (Final Permit)	Bituminous Coal TDF	N.A.	N.A.	N.A.	0.015 (Filt.PM)	0.20 (24-hr)	0.07 (30-day)	0.15 (30-day)	0.0036 (30-day)	SNCR, LI, FDA, FF GCP
East Kentucky Power Spurlock 4		300	06/12/06 (Final Permit)	Bituminous Coal TDF	N.A.	N.A.	N.A.	0.009 (Filt.PM) 0.012 (Tot.PM)	0.15 (24-hr)	0.07 (30-day)	0.10 (30-day)	0.002 (3-hr)	SNCR, LI, FDA, FF GCP
Cleco Rodemacher Unit 3 ^c	LA	270	02/23/06 (Final Permit)	Bituminous Petroleum Coke Lignite	N.A.	N.A.	N.A.	0.011 (Filt.PM)	0.15 (30-day)	0.07 (12-month)	0.10 (30-day), 0.15 (30-day, part-load)	0.0047 (30-day), 0.0070 (30-day, part-load)	SNCR, LI, SDA, FF GCP
Southern Montana Highwood Generating	MT	250	5/30/2007 (Final Permit)	Sub-bituminous Coal	8,600	0.80%	N.A.	0.012 (Filt.PM) 0.026 (Tot.PM ₁₀)	0.057 (3-hr) 0.048(24-hr) 0.038 (30-day)	0.10 (1-hr) 0.09(24-hr) 0.07(30-day)	0.10 (3-hr)	0.003 (3-hr)	SNCR, LI, FAR, FF GCP
Montana-Dakota Utilities Westmoreland (not constructed)	ND	175	05/03/05 (Final Permit)	Lignite Coal	5,500 Design	N.A.	16.50% Maximum	0.0130 (Filt.PM ₁₀) 0.0275 (Tot.PM ₁₀)	0.038 (30-day)	0.09 (30-day)	0.154(3-hr)	0.005 (3-hr)	SNCR, LI, SDA, FF GCP
Reliant Energy Seward	PA	520	08/25/03 (Final Permit)	Waste Coal	N.A.	N.A.	N.A.	0.010 (Filt.PM ₁₀)	0.60 (3-hr)	0.15 (3-hr)	0.15 (3-hr)	0.005 (3-hr)	SNCR, LI, FAR, FF GCP
Robinson Power Beach Hollow	PA	270	04/01/05 (Final Permit)	Waste Coal	N.A.	N.A.	N.A.	0.012 (Filt.PM ₁₀)	0.245 (3-hr)	0.15 (30-day)	0.15 (1-hr)	0.006 (1-hr)	SNCR, LI, SDA, FF GCP
Wellington Development Greene Energy	PA	525	07/05/05 (Final Permit)	Waste Coal	N.A.	N.A.	N.A.	0.015 (Filt.PM) 0.050 (Tot.PM ₁₀)	0.234 (3-hr) 0.156(30-day)	0.10(24-hr) 0.08 (30-day)	0.20 (1-hr)	0.005 (1-hr)	SNCR, LI, SDA, FF GCP
River Hill Power	PA	270	07/21/05 (Final Permit)	Waste Coal	N.A.	N.A.	N.A.	0.03 (Filt.PM) 0.05 (Cond.PM ₁₀)	0.274 (3-hr) 0.200(30-day)	0.07 (30-day)	0.20 to 0.25 (1-hr)	0.0050 (1-hr)	SNCR, LI, SDA, FF GCP
AES Puerto Rico, LP	PR	454	10/29/01 (Final Permit)	Bituminous Coal	11,600 Design	0.76% Design	8.80% Design	0.015 (Filt.PM) 0.015 (Tot.PM ₁₀) ^d	0.022 (3-hr)	0.10 (24-hr)	0.10 (8-hr)	0.0047 (3-hr)	SNCR, LI, CDS, ESP GCP
Deseret Generation Bonanza	UT	110	8/30/2007 (Final Permit)	Waste Coal	N.A.	N.A.	N.A.	0.012 (Filt.PM) 0.03 (Tot.PM)	0.055 (30-day)	0.08 (30-day)	0.15 (30-day)		SNCR, LI, FF GCP

Attachment 2 - CFB Boilers													
NEVCO Energy Sevier Power	UT	270	10/12/04 (Final Permit)	Sub-bituminous Coal	N.A.	N.A.	N.A.	0.0154 (Filt.PM)	0.050 (24-hr) 0.022 (30-day)	0.1 (24-hr)	0.115(1-hr)		SNCR, LI, SDA, FF GCP
Manitowoc Public Utilities	WI	64	12/03/03 (Final Permit)	Bituminous Petroleum Coke	13,000	_3.5% (max)	_8.9% (max)	0.030 (Filt.PM)	0.125(30-day)	0.155 (30-day)	0.15 (30-day)	0.013 (3-hr)	LI, FF GCP
Western Greenbrier	WV	98	04/26/06 (Final Permit)	Waste Coal	12,000	_1.47%	_63.71%	0.015 (Filt.PM) 0.030 (Tot.PM ₁₀)	0.14 (3-hr) 0.14 (24-hr)	0.10 (30-day)	0.20 (24-hr)		SNCR, LI, FDA, FF GCP
AES Thames	CT	270	7/29/1987	Coal/ Petroleum coke	NA	NA	NA	0.0144 (Filt.PM)	0.32 (3-hr)	0.15	0.15	0.0095 (TNMH)	FGD, LI, FF
JEA Northside Generating (2 CFBs)	FL	297.5 (each)		Coal/ Petroleum Coke	NA	6.70%	NA	0.011 (Filt.PM)	0.2 (24-hr) 0.15 (30-day)	0.09 (30-day)	350 lb/hr (24-hr)	14 lb/hr (3-hr)	SDA, FF
Indeck Elwood LLC.	IL	660	03/21/02 (Received)	Bituminous Coal	9,965 Nominal	3.51% (wt) Nominal		0.015 (Filt.PM/ PM ₁₀)	0.15 (30-day)	0.10 (30-day)	0.11(24-hr)	0.004 (3-hr)	SNCR, LI, FF, TS GCP
Archer Daniels Midland Co.	IL	NA	8/18/2004 (Received)	Coal	NA	~1%	NA	0.025 (Filt.PM)	0.7 (30-day)	0.12	0.1	0.032	LI, SNCR, FF
Black River Generating LLC. (3 CFBs)	N	73	2/26/2007	Coal, Petroleum coke, Wood chips, TDF	16,000	1.5% (wt.)	NA	0.07 (Filt.PM)	NA	NA	NA	NA	LI, FF
Niagara Generating LLC.	N		1/20/2006	Coal	NA	NA	NA	NA	0.5 (30-day)	NA	NA	NA	SNCR, LI, FF
Grant Town Power Plant (2 CFBs)	WV	80	12/22/2003	Coal Refuse	NA	NA	NA	0.03 (Filt.PM)	0.83 (3-hr)	0.4 (3-hr)	0.17	0.008	FF, CS
Morgantown Energy Associates (2 CFBs)	WV	110	10/7/2003	Coal/ Coal refuse	NA	3.5	51.70%	0.03 (Filt.PM)	0.4 (24-hr)	0.4 (24-hr)	0.157	0.0074	FF, LI
North Branch Power Station (2 CFBs)	WV	175	3/29/2005	Coal/ Coal refuse	NA	NA	70%	0.03 (Filt.PM)	0.678 (24-hr)	0.4 (24-hr)	0.17	0.005	LI, SCR, FF

ATTACHMENT 3

Introduction

Dominion Energy (Dominion) requested that CH2M HILL prepare an analysis of the cost-effectiveness of alternative power generation technologies for the air permitting process for the Virginia City Hybrid Energy Center (VCHEC). This analysis would evaluate the incremental cost per ton of emissions reduced when comparing the circulating fluidized bed (CFB) technology selected for VCHEC with a hypothetical Integrated Gasification Combined Cycle (IGCC) unit using the VCHEC design fuel, and a hypothetical Supercritical Pulverized Coal (SCPC) unit using cleaned eastern bituminous coal.

Disclaimer

It is important to note that this analysis is based on using the VCHEC design fuel in a hypothetical IGCC unit. As the discussion below shows, the VCHEC design fuel is technically unacceptable for use in IGCC power generation technology. For the purposes of this analysis, the costs and operating characteristics of a “hypothetical IGCC unit” were estimated. In no way does this hypothetical analysis validate the potential for design or operation of IGCC power generation technology with the VCHEC design fuel.

EPA guidance does not require a BACT analysis to be done for power generation facilities that use fundamentally different combustion processes. CFB and SCPC are combustion processes that produce only steam for use in a steam turbine generator for the production of electricity. IGCC uses a gasifier to produce synthesis gas for combustion in gas turbines that produce electricity. Waste heat from the gas turbine exhaust is used to make steam for additional power generation. Thus, CFB and SCPC, when compared to IGCC, are fundamentally different power generation processes and EPA guidance does not require that they be compared in an analysis such as this. However, in response to a

Virginia State Air Pollution Control Board inquiry, the alternative power generation technology analysis has been prepared.

Results

The results of the cost-effectiveness evaluation, presented as the incremental emission control cost, in \$/ton removed, for replacing the CFB technology with the hypothetical IGCC technology and the hypothetical SCPC unit are shown below in Table 1. Since CFB, SCPC and IGCC are power generation technologies, and not emission control technologies, the only way to achieve individual emission reductions would be to completely replace the CFB unit with the hypothetical IGCC unit or hypothetical SCPC unit (versus substituting only emission control systems as is the purpose of the BACT analysis). Therefore, the incremental costs are a function of the overall higher capital and operating costs of IGCC and SCPC technologies compared to the CFB technology.

These costs per ton controlled were derived by computing the increased annual costs individually for the hypothetical IGCC and hypothetical SCPC options over the CFB option and dividing the differences by the annual reduction in emissions compared to the CFB option. Changing from the CFB technology selected for VCHEC to the either the hypothetical IGCC or hypothetical SCPC technology would not be cost effective.

Table 1. Emission Reduction Costs for IGCC and SCPC vs. CFB

<u>Pollutant</u>	<u>Incremental Emission Control Cost, \$/ton Removed</u>	
	IGCC	SCPC
NO _x	178,857	248,650
SO ₂	30,483	144,763
CO	25,866	115,811
VOC	1,403,285	555,870
PM	563,050	N/A*

* Incremental PM Control Cost is negative because SCPC emits more PM compared to CFB.

Technology Descriptions

Dominion has previously provided the Virginia Department of Environmental Quality (DEQ) with detailed descriptions of CFB, IGCC and SCPC power generation technologies. Those detailed discussions will not be repeated here. However, it is important to understand the main distinguishing characteristics of each of these power generation technologies. For CFB and SCPC, the coal is the “fuel”. For IGCC, the coal is the feedstock for the chemical conversion process producing syngas that becomes the actual “fuel”, which is cleaned and then combusted in gas turbines.

While CFB and SCPC actually combust the coal, the gasification process used in IGCC power plants does not. Gasification is a chemical conversion process that converts the carbon and moisture in the coal (or other feedstock or blend of feedstocks) into a synthetic gas (syngas) composed primarily of carbon monoxide, hydrogen, water, carbon dioxide and methane. In modern gasifiers used in IGCC power plants, this conversion process occurs at temperatures of 2,500-2,900°F and pressures of 400 psi or greater, using only a small fraction of the air or oxygen that would be needed to

combust the coal. While CFB boilers require excess air in order ensure complete combustion of the carbon in the coal, IGCC is “oxygen-starved”.

Combustion in SCPC boilers involves first crushing and pulverizing the coal particles to the consistency of powder, and then blowing the coal powder into the boiler through specially designed burners. SCPC technology is commercially available for a wide range of domestic coals, including bituminous, subbituminous and lignite. While each individual unit must be designed for a narrow range of fuels, SCPC technology would not be suitable for a fuel mix such as that proposed for the VCHEC facility (run-of-mine (ROM), gob, and biomass). The size of the boiler is dependent on the type of coal used. High quality bituminous coals are able to burn quickly, with short residence times. Lower quality subbituminous and lignite coals take longer for the carbon to burn out, due to their higher content of moisture and lower amounts of volatile matter with a high heating value. Boilers designed for lower quality coals must provide additional residence time for complete burnout, and are larger (typically taller) than those designed for bituminous coal.

Further, ash content has detrimental effects on the combustion in SCPC boilers. As ash content increases, the fixed carbon and volatile matter contents of the coal necessarily decreases. Since ash does not combust, higher ash content results in lower heating value. For low volatile matter and high ash coals, SCPC technology does not provide sufficient flame stability, residence time or carbon burnout.

As Dominion has previously described, CFB technology is ideal for the combustion of low quality fuels, as it provides long residence time in the fluidized bed, assuring carbon burnout. CFB technology is proven worldwide for use with low quality fuels. Information submitted by Dominion to the DEQ provides the following analysis for the low quality fuel to be used at VCHEC:

“The coal for this project consists of run-of-mine Virginia coal with an average heating value of , Btu lb and a maximum ash content of and waste coal with a heating value of , Btu lb and a maximum ash content of . .”

This combination of high ash, low volatile matter, and low heating value makes the coal unacceptable for use in a SCPC boiler. These characteristics are even worse for the waste coal. As Dominion has previously discussed, CFB technology is the best choice for efficiently and effectively combusting the coal and/or waste coal to be used for VCHEC.

IGCC Technology

Impacts of Coal Quality on IGCC Design and Performance

Since the purpose of a gasifier is to convert carbon to syngas, the higher the carbon content in the feedstock, the higher the conversion of the feedstock to syngas. Gasifiers work more efficiently with high-carbon feedstocks, such as bituminous coal (typically 70% carbon) and petroleum coke (typically 80% carbon), although volatile matter adds to the overall reactivity of the feedstock because it can gasify faster than carbon. The lower the quality of the coal (higher ash and moisture content), the less efficient the gasification conversion process. Coal quality is directly impacted by the ash and moisture content of the coal. As ash and moisture content increase, carbon content necessarily has to decrease, further reducing the heating value (in Btu/lb) and quality of the coal.

High fuel ash content is a drawback for all gasifiers. In the gasifier, the ash must be heated to gasification temperature by burning fuel, usually with pure oxygen, so it represents a thermal loss to the system (reduced plant efficiency). At the high temperatures of oxygen-blown gasification, the ash is converted to a molten slag, which then flows from the bottom of the gasifier into a water bath. There, the slag is quenched and it solidifies into a black, glassy material. For refractory-lined gasifiers, some amount of slag is needed to protect the hot face of the refractory. However, as ash content increases, more slag results in higher erosion rates for the refractory, resulting in a shorter

life, more required maintenance and earlier replacement. Replacement of refractory is not only expensive, but it takes considerable time so that the downtime for replacement directly impacts IGCC plant availability.

For gasifiers with membrane walls, a minimum ash content is necessary in order to provide an insulating, protective coating to the tubing. Below that value, heat loss increases and the surface temperature of the membrane wall may become too high, risking high temperature corrosion. The gasifier industry uses a guideline of about 5% ash (dry basis) minimum for gasifiers with membrane walls. However, the higher the ash content, the greater the impacts on gasifier performance and heat transfer.

For all types of gasifiers, the higher the ash content of the feedstock, the greater the design capacity of the ash and slag handling systems. This increases cost and complexity, as well as reducing the overall efficiency as noted above. More ash means more slag, and the slag handling equipment experiences more maintenance and replacement due to the erosive and corrosive nature of the slag. Along with coal handling equipment, ash/slag removal and handling equipment is the most troublesome equipment in an IGCC plant.

The U.S. Environmental Protection Agency (EPA) addressed low quality coal use in IGCC plants in its report entitled “Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies,” EPA-430/R-06/006, July 2006. In this report, EPA noted that “relatively little research or commercial work has been done to investigate gasification of low rank coals, including subbituminous and lignite, for electric generation purposes.” The two IGCC plants currently operating in the U.S., Wabash River Generating Station (Indiana) and Polk Power Station (Florida) were designed for high heating value, low ash content, eastern bituminous coals. The Wabash River Generating Station now uses up to 100% petroleum coke as its feedstock. Polk Power Station uses a blend of up to 60% petroleum coke with 40% bituminous coal. The use of petroleum coke as an opportunity feedstock was initiated after several years of operation on coal, and after considerable testing of different coal/petroleum coke blends.

Gasifiers do have some feedstock flexibility, meaning that they may be able to operate with off-design feedstocks. However, when using lower grade feedstocks, performance, carbon conversion, and overall efficiency are reduced. Note, however, that the “off-design” feedstocks now utilized at both Wabash River Generating Station and Polk Power Station are higher quality feedstocks, not lower quality feedstocks. Further, gasifiers (and the balance of the entire IGCC plant) operate best when the feedstock quality is stable. Radical changes in feedstock characteristics lead to changes in slurry concentration, changes in gasifier temperature (and therefore changes in conversion of the carbon to syngas), and changes in the response of particulate and sulfur removal systems. Further down stream in the process, the gas turbine then experiences a different syngas quality, which changes its performance. The fuel supply for the VCHEC facility includes a mix of fuels ranging from ROM coal to waste coal to biomass.

Experience with Low Rank Coals in Gasifiers

Presently, there are only two operating electric utility coal-based IGCC facilities in the United States. Both were designed to use eastern bituminous coal. Several non-utility IGCC demonstration plants (which were later dismantled) and one commercial coal gasification plant (not IGCC) were designed to use low rank subbituminous or lignite coals. None were designed to use the type of fuels and fuel mix planned for VCHEC. Following is a discussion of some of these facilities.

Gasifiers can be designed for lower grade coals, such as subbituminous and lignite. Subbituminous coal (about 30% moisture) from the Powder River Basin (PRB) in Wyoming was used in the Louisiana Gasification Technology, Inc. (LGTI) demonstration plant in Plaquemine, Louisiana from 1987-1995. Almost 4 million tons of this coal was successfully gasified during the demonstration period. This technology is now commercially available as the E-Gas technology offered by ConocoPhillips. Note however, that PRB coal typically has a carbon content of 45-50%, a heating value in the 8,300-8,800 Btu/lb range, and an ash content of 6%. The ash content is far lower than for the design fuel for VCHEC.

During this same timeframe, Shell demonstrated its Shell coal gasification technology at its Deer Park facility in Texas. This demonstration plant tested a wide variety of feedstocks, from low quality Texas lignite to high quality petroleum coke. Texas lignite typically has carbon content of 35%, a heating value of about 6,000 Btu/lb, and an ash content of about 15%. Again, even this lignite is considerably lower in ash content than the design fuel for VCHEC.

The Great Plains Gasification facility in Beulah, North Dakota has been gasifying North Dakota lignite for over 25 years, converting the syngas to synthetic natural gas for sale. The facility uses fixed-bed Lurgi gasifiers, which operate at lower temperatures than the entrained-flow gasifiers used in modern IGCC plants. The lignite, mined locally, has a carbon content of about 45%, heating value of 6,900 Btu/lb, and an ash content of 6.5%. It is a high moisture coal, with a moisture content of 37%. The high moisture, not the ash content, is what makes this lignite low in heating value. While this low quality coal is used successfully in a gasifier, it is also considerably lower in ash content than the design fuel for VCHEC.

Other gasifiers are being designed for low quality coals. The Kellogg Brown Root (KBR) transport gasifier is being demonstrated at the Power Systems Development Facility near Wilsonville, Alabama, adjacent to one of Alabama Power Company's power plants. There, PRB coal has been successfully tested in this unique gasifier. Again, this is a low ash, high moisture subbituminous coal. The gasifier size is only about 4-6 MW equivalent. This gasification technology has not been demonstrated at large scale. A 550 MW (net) plant using the KBR technology with Mississippi lignite is being planned by Mississippi Power Company. The Mississippi lignite that the plant expects to use will have an average analysis of 4,921 Btu/lb, 1% sulfur, 10.85% ash, and 38-40 % moisture (as received basis). As with other modern IGCC systems, it is necessarily being designed for low ash content coal.

GE Energy is an active developer and technology supplier in the gasification and IGCC industry. At the 2007 Gasification Technologies Conference, a presentation provided by Mr. John Lavelle, General Manager, Gasification for GE Energy, provided information on the type of coal that the

GE gasification technology is designed to use. The GE gasification technology is designed for an eastern bituminous coal, with up to 14% ash. This further supports the fact that high ash coal is not technically acceptable for use in gasifiers used in modern IGCC plants.

ConocoPhillips is another leader in the gasification and IGCC industry. At the 2005 Gasification Technologies Conference, ConocoPhillips presented a paper entitled “Comparative IGCC Performance and Costs for Domestic Coals”. This comprehensive study, which was performed for their E-Gas gasification technology, included design and cost information for petroleum coke, two types of bituminous coal, and PRB coal. No high ash coals were included in their study. This slurry-feed, refractory-lined gasifier technology is not designed to use high ash coals, for the reasons described above.

Clearly, the information provided herein demonstrates that high ash coals are technically unacceptable for IGCC technology. There is no demonstrated IGCC experience with feedstocks similar to the design fuel for the VCHEC facility.

Impacts of Coal Quality on IGCC Cost

While the information provided above demonstrates that the high ash content of the VCHEC design fuel makes it technically unacceptable for use with IGCC, it is important to consider potential cost impacts of using low quality feedstocks in IGCC power plants. Most of the IGCC plants being proposed at this time for operation in the 2011-2014 time period are based on the use of high quality (low ash) eastern, bituminous coal. One good example is Appalachian Power Company’s proposed IGCC plant to be located at its Mountaineer Plant in West Virginia. The design coal for this plant, based on GE Energy gasification technology, is West Virginia bituminous coal, with a heating value of 12,808 Btu/lb and ash content of 11%.

Appalachian Power Company serves customers in West Virginia and Virginia. Therefore, it is required to obtain approvals for cost recovery from commissions in both states. While the West Virginia Public Service Commission approved the costs for the plant, the Virginia State Corporation Commission (SCC) did not. In its submittals to the SCC, Appalachian Power Company noted that the total installed cost of the IGCC plant would be “approximately \$2.23 billion”. With a net output of 629 MW, this calculates to be \$3,545/kW (net), with operation planned in 2012.

Similar costs have been provided in publicly available information submitted for the following IGCC projects:

Duke Energy Edwardsport : \$1.98 billion, or \$3,150/kW (eastern bituminous)

Excelsior Energy, Mesaba Project (delayed): \$2.156 billion, \$3,594/kW (blends of eastern bituminous, PRB and petroleum coke)

Tampa Electric Company, Polk Power Station Unit #6: (cancelled): \$2.0 billion, or \$3,180/kW (blends of eastern bituminous and petroleum coke)

This shows a range for IGCC technology of \$3,150-3,594/kW. The Mesaba IGCC project is higher in cost, particularly due to design considerations for the PRB coal, which requires substantially more coal throughput due to the lower heating value of PRB coal. Therefore, the coal storage, handling and coal slurry preparation systems are larger than those for IGCC plants designed only for eastern bituminous coals (alone or blended with petroleum coke).

The presentation by ConocoPhillips (noted above) provides cost comparison information for the various types of feedstocks. On average, an IGCC plant designed for low quality PRB coal would cost about 30% more than for one designed for bituminous coal. Some of that cost increase is due to the higher amount of coal throughput required, since PRB coal has a heating value of about 2/3 that of bituminous coal. Put another way, the PRB-based IGCC plant would require 50% more coal throughput, resulting in larger, more expensive coal handling and slurry preparation systems. No information is provided for the cost multiplier for using a high ash coal, since that is neither technically feasible nor commercially available for IGCC.

For the purposes of this hypothetical cost-effectiveness analysis, the hypothetical IGCC plant would be designed to use low quality coal. The cost multiplier would be at least that for using PRB coal. Therefore, the Appalachian Power Company IGCC plant would cost at least \$2.9 billion, or \$4,610/kW (net) if it could be designed to use low quality PRB coal. Additional cost impacts would result from design changes to handle the lower heating value and higher ash VCHEC design fuel.

The Appalachian Power Company IGCC plant is designed to use 5,621 tons/day of bituminous coal, producing 618 tons/day of slag. Using a PRB coal with a heating value of 8,300 Btu/lb and 5% ash would require 8,675 tons/day of PRB coal, producing 434 tons/day of slag. Therefore, the coal handling and preparation system for PRB coal would need to be increased in size by 54% over that for the eastern bituminous coal. Using the VCHEC design fuel heating value of 7,782

Btu/lb and ash content of 44%, the hypothetical IGCC plant would require a throughput of 9,316 tons/day of coal and would produce 4,100 tons/day of slag. This would require an increase of 66% in coal throughput (compared to using eastern bituminous coal) with significant increases in the size and cost of the coal handling and slurry preparation systems. The ash handling system would need to be increased in size by over 500%. The 30% capital cost multiplier would need to be further increased for the hypothetical IGCC plant using the VCHEC design fuel instead of PRB coal. For this hypothetical analysis, a 35% capital cost multiplier (compared to an IGCC plant designed for eastern bituminous coal) will be used.

Therefore, the capital cost of the hypothetical IGCC plant designed to use the VCHEC fuel would be at least \$3 billion, or \$4,786/kW (based on a 629 MW net plant). Scaling the IGCC plant size down to 585 MW (net) output at the same \$/kW value, the cost of the hypothetical IGCC plant at VCHEC would be \$2.8 billion.

The VCHEC plant is estimated to cost \$1.8 billion for 585 MW (net). Therefore, the hypothetical IGCC plant would cost 55% more than the CFB technology selected for VCHEC.

This analysis will use the annual emissions provided by Appalachian Power Company, reduced proportionately from 629 MW (net) to 585 MW (net), for the hypothetical IGCC plant.

Annual Costs

It is impossible to precisely determine the annual O & M costs for a hypothetical IGCC unit using a feedstock that is unacceptable for use in it. The U.S. Department of Energy's report "Cost and Performance Comparison of Fossil Energy Power Plants", May 2007, provides detailed estimates for O & M costs for IGCC plants using eastern bituminous coal. For the GE Energy-based IGCC plant example in the report, total fixed operating costs are \$22.6 million/year, and total variable operating costs are \$22.1 million/year. Total O & M costs are \$44.7 million/year. Of course, actual O & M costs would be much higher, especially in the slag handling and disposal system sizes and costs. Due to the significantly higher ash erosion and corrosion impacts, refractory and piping system replacements would be much more frequent and much more expensive. For this analysis, we are using these costs on an unadjusted basis, but would expect them to be significantly higher.

Fuel Costs

For the purposes of this analysis, the VCHEC design fuel will be utilized for the hypothetical IGCC unit cost-effectiveness calculations. Per Dominion Energy, the fuel cost is \$3.19/MMBtu.

SCPC Technology

Dominion has previously provided detailed technical descriptions of SCPC technology to DEQ. As noted above, the coal and waste coal which will be the fuels for VCHEC are unacceptable for use in a SCPC boiler. A SCPC boiler does not provide sufficient residence time for a high ash, low volatile matter coal to completely combust.

Impacts of Coal Quality on SCPC Design and Performance

SCPC boilers are designed to combust carbon. It is the carbon content that provides the primary heating value of the coal. Carbon exists in two main forms in coal: fixed carbon and volatile matter. The volatile matter is important in maintaining flame stability and quick burnout of the fixed carbon. As the moisture and ash contents of the coal increase, the total carbon content necessarily decreases, and the heating value of the coal is reduced. As noted above, lower quality coals require longer residence times for complete burnout, so that boilers designed for lignite are typically larger (taller) than those designed for subbituminous (PRB) coals, and they are larger than boilers designed for bituminous coals. While anthracite coal has very high carbon content, it is mostly in the form of fixed carbon, with little volatile matter. Because of this, anthracite is very difficult to ignite, and it is not typically used in PC boilers unless it is blended with other coals that provide the necessary volatile matter.

Higher ash content also reduces SCPC boiler combustion efficiency, since the ash can coat or “blind” carbon particles. In addition, boiler efficiency is reduced since part of the heat produced during the combustion process is used to heat the fly ash and bottom ash to furnace temperature. Much of this heat is then lost as the fly ash and bottom ash are

removed from the boiler for disposal. Therefore, higher ash coals require larger and more expensive fly ash and bottom ash handling systems for SCPC boilers. Combining the impacts from longer residence time requirements and increased ash production, SCPC boilers designed for lower quality coals are more expensive than those designed for bituminous coals.

High ash coals, such as the design fuel for VCHEC, have such poor characteristics that they are technically unacceptable for use in a SCPC boiler. The waste coal is even worse, and neither flame stability nor carbon burnout would occur. That is why a CFB boiler must be used for these low grade coals and waste coals.

Costs for SCPC Technology

A good example of SCPC technology designed for eastern bituminous coal is Santee Cooper's proposed Pee Dee Electrical Generating Station in South Carolina. The plant will have two 660 MW (gross)/600 MW (net) SCPC units. While detailed plants costs are not yet publicly available, this analysis will use the design characteristics of the Pee Dee units along with the estimated costs for a SCPC unit, as submitted by Appalachian Power Company as part of their economic analysis of the Mountaineer IGCC facility. In "Exhibit No. 4, rev. 1" of testimony submitted by Mr. Michael Renchek, Appalachian Power Company provided detailed estimates of the costs of various coal-based power generation technologies, based on several types of coal. The table notes the following costs for SCPC and IGCC technologies designed for eastern bituminous coal:

- IGCC: \$2,861/kW
- SCPC: \$2,189/kW

These values are year 2006 "overnight" capital costs and do not include interest costs during construction, nor escalation to the in-service year of the proposed plant of 2012. As noted above, Appalachian Power Company submitted a total installed cost value of \$2.23 billion (\$3,545/kW) to the Virginia State Corporation Commission. This value does include escalation to 2012 and does include interest costs during construction. Using that value, and applying this same ratio to the SCPC cost, the SCPC plant cost

estimate would be \$2,712/kW in 2012. For 585 MW (net), the cost of the hypothetical SCPC plant would be \$1.59 billion, for use with clean, bituminous coal.

Fuel Costs

For the purposes of this analysis, a cleaned, eastern bituminous coal would be the design fuel for the hypothetical SCPC unit. Per Dominion Energy, the cost of such coal is \$4.21/MMBtu delivered.

Annual Costs

For this hypothetical analysis, annual O&M costs from the U.S. Department of Energy's report referenced above are used. Exhibit 4-35 of that report provides annual O&M costs for a SCPC unit designed for eastern bituminous coal. The total fixed operating costs are \$13.85 million/year and the total variable operating costs are \$19.95 million/year. Therefore, total O&M costs are \$33.85 million/year.

Data Table

The table below presents the information to be used for the cost-effectiveness calculations. Sources of the data are noted below the table.

	Virginia City Hybrid Energy Center CFB¹	Appalachian Power Company IGCC²	Hypothetical IGCC Plant³	Hypothetical SCPC⁴
MW gross	668	784	729	643.5
MW net	585	629	585	585
Capacity factor	90%	85%	85%	90%
Capital cost, \$B	1.8	2.23	2.8	1.59
Capital cost, \$/net kW	3,077	3,545	4,786	2,712
Heat rate, Btu/net kWh	9,377	9,539	9,539	9,500
SO ₂ , TPY	3,292.36	586.44	545	2,996
NO _x , TPY	1,920.54	1,561.5	1,452.3	1,748
CO, TPY	4,115.45	943.7	877.7	3,745
VOC, TPY	137.18	83.35	77.5	60
PM (total), TPY	329.24	194.1	180.5	449
Total Emissions, TPY	9,794.8	3,369.1	3,133	8,998
Fuel cost, \$/MMBtu	3.19	4.21	3.19	4.21

Table Notes:

1 - Data provided by Dominion Energy. Emission data from VCHEC draft permit.

2 - Unit ratings and costs from Appalachian Power Company submittals to West Virginia Public Service Commission. Emissions are from the permit application for the Mountaineer IGCC facility submitted to the West Virginia Department of Environmental Protection. Fuel cost is as provided by Dominion Energy for clean eastern bituminous coal.

3- Unit ratings are scaled based on the direct ratio of 629 MW net for the Mountaineer IGCC plant to the 585 MW net capacity for the VCHEC. Capital cost is based on a hypothetical IGCC plant as described above, designed for use of the VCHEC design fuel. This study assumes that regardless of coal, the emission would be the same for IGCC. To be more accurate, the annual emissions are scaled from the 629 MW net Mountaineer Plant to the 585 MW net level for the hypothetical IGCC plant.

4- Unit ratings are scaled based on publicly available information from Santee Cooper for its proposed Pee Dee Electrical Generating Station, which will use SCPC technology and is being designed for cleaned eastern bituminous coal. Capital cost is as calculated above, based on SCPC cost data provided in Appalachian Power Company's coal-based power generation technology comparison, which was submitted to the West Virginia Public Service Commission. O&M costs are per U.S. DOE report. Fuel cost is as provided by Dominion Energy for cleaned eastern bituminous coal. Emissions are from the draft permit for the Pee Dee Electrical Generating Station, issued by the South Carolina Department of Health and Environmental Control. For this analysis, it is assumed that the annual emissions would not change.

ATTACHMENT 4

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Pollutant	Control ec nolog	Percent Control	ec nicall Feasible	Control Cost \$/ton	Expected Controlled Emission Rates				Potential ncontrolled Emissions tp	Expected Emission Reduction tp	Control Cost Comments
					lb/mmBtu	lb/ r	lb/M r	tp			
NOx	SCR	80	No	42,000	0.03	187. 2	0.32	823.0	6,310	5,487	SCR is not tec nicall easible in t e traditional sense. SCR ould onl t eoreticall be possible at t e tail end o t e abric ilter s stem ic ould re uire re eat o t e ex aust gas. is scenario re uires combustion o more uel t us reducing t e plant s e icienc .
	Stage Combustion SNCR	70	es	400 to 2,500	0.07	438.48	0.75	1 20.54	6,310	4,3 0	EPA s Air Pollution Control ec nolog Fact S eet 2003 ollars
SO2	imestone In ection	80	es		0.12	3 .6	1.61	4115.45	164,618	160,502.472	
	r Scrubber	0	es	150 300							EPA s Air Pollution Control ec nolog Fact S eet 2001 ollars
	et Scrubber	0	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible due to ater consumption concerns
	o Sul ur Coal	Note	es	26, 50							SO2 emissions are predominantl a unction o t e combined control s stems and not directl driven b coal sul ur content. ere ore establis ing an SO2 emissions reduction rom lo er coal sul ur content is ver di icult to estimate because lo ering t e coal sul ur content does not necessaril translate to lo er SO2 emissions. See Response to Comment 1 or a discussion on coal as ing costs and emissions.
CO	Oxidation Catal st	0	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible
	Combustion Controls	50	es	NA	0.15	3 .6	1.61	4115.45	8,231	4,115	Operational not a control device
VOC	Oxidation Catal st	0	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible
	Combustion Controls		es	NA	0.005	31.32	0.05	137.18	13,718	13,581	Operational not a control device
PM	Fabric Filter	.	es	42 266	0.012	75.168	0.13	32 .24	365,818	365,488	EPA s Air Pollution Control ec nolog Fact S eet 2003 ollars
	ESP	.	es	43 640	0.012	75.168	0.13	32 .24	365,818	365,488	EPA s Air Pollution Control ec nolog Fact S eet 2002 ollars
	est ESP	.	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible

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Pollutant	Control ec nolog	Percent Control	ec nicall Feasible	Control Cost \$/ton	Expected Controlled Emission Rates				Potential ncontrolled Emissions tp	Expected Emission Reduction tp	Control Cost Comments
					lb/mmBtu	lb/ r	lb/M r	tp			
NOx	SCR	80	es	248,650	0.07	416.4	0.71	1824.22	5,843	4,01	See able 1 o Attac ment 3. Emissions based Attac ment 4, page 15.
	SNCR	70	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible
	FGR Staged Combustion	30	es	NA	ec ni ues used to arrive at 0.06						Part o t e boiler design
SO2	r Scrubber	8	es	144,763	0.12	6 .57	1.20	3064.11	156,332	153,268	See able 1 o Attac ment 3. Emissions based Attac ment 4, page 15.
	et Scrubber	8	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible due to ater consumption concerns
	o Sul ur Coal	Note	es	144,763							SO2 emissions are predominantl a unction o t e combined control s stems and not directl driven b coal sul ur content. ere ore establis ing an SO2 emissions reduction rom lo er coal sul ur content is ver di icult to estimate because lo ering t e coal sul ur content does not necessaril translate to lo er SO2 emissions. See Response to Comment 1 or a discussion on coal as ing costs and emissions.
CO	Oxidation Catal st	0	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible
	Combustion Controls	50	es	NA	0.15	8 2.31	1.53	3 08.30	7,817	3, 08	See able 1 o Attac ment 3. Emissions based Attac ment 4, page 15.
VOC	Oxidation Catal st	0	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible
	Combustion Controls	0	es	NA	0.002	14.30	0.02	62.62	1,270	1,208	See able 1 o Attac ment 3. Emissions based Attac ment 4, page 15.
PM	Fabric Filter	.	es	negative	0.018	106. 8	0.18	468.58	520,643	520,175	See able 1 o Attac ment 3. Emissions based Attac ment 4, page 15.
	ESP	.	es	negative	0.018	106. 8	0.18	468.58	520,643	520,175	See able 1 o Attac ment 3. Emissions based Attac ment 4, page 15.
	et ESP	.	No	NA	NA	NA	NA	NA	NA	NA	Not Feasible because et scrubber not easible

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Pollutant	Control Technology	Percent Control	Technically Feasible	Control Cost \$/ton	Expected Controlled Emission Rates*					Potential uncontrolled CO Emissions tpy	Expected Emission Reduction tpy	Control Cost Comments
					CO lb/mmBtu	Flare thermal Oxidizer lb/hr	Facility Emissions total					
							lb/hr	lb/M	tpy			
NOx	SCONOx	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not feasible due to potential catalyst fouling from SOx gases
	SCR	80	Yes	178,857	0.057*	68.10	238.40	0.38	1,562	7,400	5,280	See table 1 of Attachment 3.
	SNCR	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not technically feasible.
	Fluent Injection	NA	Yes	NA	Included in the SCR values part of the CCS system.							Part of turbine design
	Low NOx Burners	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Determined to be explosion hazard in AEP BAC.
	FGR	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not a mature technology for CCS.
SO2	FG	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Never been applied to a CCS.
	Chemical Absorption	25	Yes	30,483	0.017*	835.8	887.10	1.41	586	155,125	154,530	See table 1 of Attachment 3.
Physical Absorption												
CO	SCONOx	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not feasible due to potential catalyst fouling from SOx gases
	Oxidation Catalyst	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not feasible due to potential catalyst fouling from SOx gases
	Good Combustion Practices	50	Yes	25,866	0.031*	320.3	413.6	0.66	44	1,620	685	See table 1 of Attachment 3.
VOC	SCONOx	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not feasible due to potential catalyst fouling from SOx gases
	Oxidation Catalyst	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not feasible due to potential catalyst fouling from SOx gases
	Good Combustion Practices	0	Yes	1,403,285	0.001*	0.7	3.	0.01	83	263	180	See table 1 of Attachment 3.
PM	ESP	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not appropriate for gas combustion
	Fabric Filters	NA	No	NA	NA	NA	NA	NA	NA	NA	NA	Not appropriate for gas combustion
	Low Ash Fuels	0	Yes	563,050	0.006*	0.	18.0	0.03	204	1,577	1,373	See table 1 of Attachment 3.
Good Combustion Practices												

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* e lb/MMBtu emission rates are based on AEP Mountaineer BAC Anal sis or t e turbines ON . ere are signi cant SO2, NOx and CO emissions rom t e flare and t ermal oxidi er.